BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

- - - - - - - - - - - - - - - - -x

IN THE MATTER OF: : Docket Number

WEST-WIDE PRICE MITIGATION : EL01-68-000

- - - - - - - - - - - - - - - - -x

Room 2-C

Federal Energy Regulatory

Commission

888 First Street, NE

Washington, D.C.

Monday, October 29, 2001

The above-entitled matter came on for technical conference, pursuant to notice, at 1:05 p.m.

BEFORE COMMISSIONERS:

CHAIRMAN PAT WOOD, III,

COMMISSIONER LINDA KEY BREATHITT

COMMISSIONER WILLIAM L. MASSEY

COMMISSIONER NORA MEAD BROWNELL

SECRETARY DAVID P. BOERGERS

APPEARANCES:

MICHAEL BARDEE, ESQ.
Lead Counsel
Office of the General Counsel

HONORABLE ANNA G. ESHOO (D-CA)
California Congressional Democrats

BILL JULIAN
California Public Utilities Commission

LYNN LEDNICKY
Dynegy, Inc.

DR. GARY STERN
Southern California Edison

DR. RICHARD TABORS
Transaction Finality Group

STEVEN VAN LEER
Duke Energy NA and Duke Energy Trading
and Marketing

-- continued --

APPEARANCES (CONTINUED):

PHIL CHABOT
City of Tacoma, Washington

G. ALAN COMNES
Enron Power Marketing

MIKE NAEVE
Portland General Electric

DEJAN SOBAJIC
Electric Power Research Institute

MARK TALLMAN
PacifiCorp and PacificCorp Power Marketing

BRIAN THEAKER
California Independent System Operator

FONG WAN
Pacific Gas & Electric

-- continued --

APPEARANCES (CONTINUED):

RICHARD L. ROBERTS, ESQ.
Steptoe & Johnson
1330 Connecticut Avenue, N.W.
Washington, D.C. 20036-1795
(202) 429-6756; FAX: (202) 429-3902
E-MAIL: rroberts@steptoe.com

ALSO PRESENT:

Jane W. Beach, Court Reporter

P R O C E E D I N G S

(1:05 p.m.)

MR. BARDEE: Good afternoon. My name is Michael Bardee. I'm with the Office of General Counsel here at the Commission.

This afternoon, we are here to discuss West-wide price mitigation for the Winter season. Earlier this year in June, the Commission issued an order setting price mitigation for California and the Western United States.

In that order, the Commission allowed an opportunity for parties to file comments on the appropriateness of that mitigation for Western United States as we come into the Winter season.

Those comments have been filed and are being reviewed now, and the purpose of this conference is to discuss the same subject.

Just the ground rules for today's conference. We'll have two panels. The first panel is seated in front of my and I'll introduce you in a minute, and after each of you has had a chance to make opening remarks of approximately five minutes or so, we'll have an opportunity for questioning from members of the Commission here, and some exchange back and forth. Then we'll bring on the second panel and do the same then.

Let me introduce the panelists for the first panel, beginning on the left:

Congresswoman Ann Eshoo, representing the California Congressional Democrats. Mr. Fong Wan from PG&E, Len Lednicky from Dynergy, Dr. Gary Stern from Southern California Edison, Dr. Richard Tabors for the Transaction Finality Group, Mr. Stephen VanLeer for Duke Energy and Duke Energy Trading and Marketing, and Mr. Phil Chabot for the City of Tacoma, Washington.

With those preliminaries over, I would like Congresswoman Eshoo to begin the proceedings please.

CONGRESSWOMAN ESHOO: Thank you very much, Mr. Bardee. Thank you for having this technical conference and the opportunity to testify today.

I am Anna Eshoo, I represent California's 14th Congressional District. For those of you that don't know the number, when I describe it, you will. It's the home of Stanford University and Silicon Valley, a very distinguished district, and I'm here today on behalf of the entire California Democratic Delegation whom, as you all know very well, weighed in very heavily relative to the energy issues that our state was faced with.

The State of California has been through a lot in the last year. As you know, at the height of the electricity crisis, average wholesale prices were a thousand percent higher than they were a year earlier, and there was no sign that they were coming down.

Supplies were abnormally low and many generators exacerbated the crisis by withholding supplies in an effort to rachet prices up.

For example, in April of this year -- and I think it's somehow a little difficult for us to think pre-9/11 -- because so much has happened to all of us and our country -- but it was in April of this year, an average of 7500 megawatts of power per day was not available to Californians because of unexplained outages.

The state has done a great deal to respond. It's added 3000 megawatts of new power with new power plants on the way. Retail rates have been raised 40 percent. Consumers have reduced consumption by approximately ten percent which I think is extraordinary, but Californians are extraordinary anyway, in my view.

The state's major utilities are reorganizing to recover from massive debt and bankruptcy. Going forward, the market needs stability until our utilities regain their financial footing.

First, we think that we must have resolution of outstanding issues pending before the FERC. In July, my colleagues and I wrote to the Commission to identify 32 pending cases that must be resolved with final orders to assist in creating a more stable electricity market in the west.

Today, I'm presenting a list to the Commission of 43 cases which I understand are still pending and which need timely resolution. From my perspective, among the most important is the resolution of the refund case.

Generators, utilities, and consumers must have this result soon to provide a sense of surety, and these refunds must be substantial for all the obvious reasons, but to also send a clear signal that price gouging and market manipulation will not be tolerated.

Second, the Commission's price mitigation measure should continue West-wide during all hours. I prefer cost-of-service pricing.

Many of us in the delegation have thought that that's a more stable and reliable alternative to the current pricing scheme, but I understand -- we all understand -- that the Commission is more than unlikely to go in that direction.

I recommend that, at a minimum, you remove the creditworthiness charge on sales into California since this provision rewards the very companies that have placed California's utilities and the state itself in financial peril.

The Commission must combat withholding by requiring generators to sell into the market when they're called upon.

I also believe that this Commission needs to be a more aggressive officer on the beat. I've appreciated the Chairman's comments in this regard and I'm of course willing to work with the Commission and state agencies to provide the necessary legislative authority to accomplish this.

Again, I thank the Commission and the Staff for organizing this technical conference. I look forward to working with you and the entire Commission on the issues I've outlined today, and with your permission, I would like to enter into the record a longer printed statement as well as the pending issues, the 43, that are before the Commission and have not been acted.

And with that, as we say in the House, I yield back the balance of my time.

(Written Statement of Ms. Eshoo follows:)

.

MR. BARDEE: Thank you, Congresswoman Eshoo, and in terms of the printed statement, that will be fine. Just I think what you need to do is give it to the Court Reporter here.

Mr. Wan?

MR. WAN: Thank you. My name is Fong Wan. I'm a Vice President with PG&E Corporation.

PG&E thanks FERC for the opportunity to present our perspective on the need for continuing market stabilization in the west. FERC has recognized, time and again, that the west is an integrated wholesale power market.

We believe that integration will be further enhanced by the creation of a strong, regional transmission organization. PG&E believes that until there is efficient stable markets with adequate supply margins to ensure effective competition exists, this Commission need to provide continued oversight of the markets in California as well as the entire west.

PG&E believes in competitive markets and that there shouldn't be price caps if the market is functional. Just as FERC does, we believe in the long run that both consumers and sellers will benefit from the creation of functional, robust markets.

PG&E is an active participant in competitive markets today and expects to play a major role for years to come. However, as FERC recognized in its June 19th West-wide mitigation order, electric markets in the west are not robust and functioning properly, and we all know that can lead to unjust results.

Since FERC properly stepped into the markets in June, things have gotten better, a lot better. But continued oversight is needed or we will find ourselves reliving the summer and winter of 2000.

PG&E believes two essential points should be drawn from the experiences of the past year-and-a-half as FERC considers where to go with its West-wide mitigation.

Point number one. Mitigation needs to be maintained in its current format including West-wide applicability and to all sellers and until a working, competitive, and functional market is put in place. Significant conservation and mild weather, along with new generation, have temporarily eased the pressure during the summer of 2001.

The markets require effective rules and institutions, multiple buyers and sellers, and careful oversight. None of these conditions really are yet in place in California or in the west.

There is currently only one real buyer in

California, a situation that will not be remedied until the California IOUs can return to the market.

Since the west is so interconnected and so import- and export-dependent, no single market can be effective in isolation.

Integrating California into an RTO spanning a large region and encompassing the bulk of California's trading partners is a needed step toward competitive markets.

Until we have designed the next market including perhaps capacity markets, and put in rules and institutions to police and maintain that market, it is too early to relax.

In the meantime, the mitigation rules should not be weakened. Sellers are smart and they will naturally use every possible bidding and trading strategy to make money. Megawatt laundering withdraws from forward markets and reselling out of market with the results of loopholes in past efforts that the June order largely cured.

Similar loopholes will reappear if FERC reduces the mitigation in the west, or just outside of California. Or if FERC ceases to apply its mitigation to all sellers, whether or not they are FERC jurisdictional and whether or not they own or just market generation.

Point number two. Unnecessary costs should be removed and caps should reflect both varying gas costs and seasonal unit availability.

In FERC's order for this conference, FERC identified one unnecessary non-incentive in its June order, the ten percent creditworthiness adder.

FERC already requires the California ISO to purchase only for creditworthy buyers since CDWR's purchasing the net open positions of the California IOUs and the CDWR is a creditworthy buyer, a premium for credit risk is unnecessary and artificially inflates the price of power to California consumers.

FERC also raised the issue of altering the calculation of price cap so that it can float up when gas prices go up. We believe that is right but only half right. It is reasonable for the cap to reflect high gas prices, just as it is likewise reasonable for the cap to go down when gas prices fall.

PG&E also believes that it is reasonable to have a cap which reflects the seasonality of marginal units with more efficient units in seasons and less efficient units in peak months.

A cap based on heat rate of units used only during emergencies merely transfers dollars to sellers without providing for any incentives. PG&E therefore recommends a ten percent penalty be terminated, the caps be adjusted up and down for changes in costs of gas as well as for seasonal changes and marginal units.

MR. BARDEE: Thank you, Mr. Wan.

Mr. Lednicky, please?

MR. LEDNICKY: I'm Len Lednicky, Senior Vice President of Dynegy Marketing Trade, and I've been involved with all phases of Dynegy's generation activities in California since 1997. I will only briefly reiterate Dynegy's position on price caps, a position that has not changed over several years of debate at this Commission.

Price caps do not provide consumer choice, provide the benefit of competition, or encourage reliable supplies. Nonetheless, for a variety of reasons, the Commission has chosen to apply price caps. Now the Commission is faced with the task of implementing its price cap policy in an environment of financial, regulatory and legal uncertainty. As is always the case, the regulatory system struggles to keep up with the real world pace of change.

As the Commission considers changes to its market mitigation program, it should first consider the current state of affairs in California to understand the context in which its market mitigation plan now exists. Today, we have bankruptcy, both official and unofficial, and endless litigation. We have increased retail rates with no retail choice.

The Department of Water Resources has entered into long-term contracts, and yet within nine months of entering those contracts, they are asking to renegotiate them. Many suppliers have not been paid for nearly ten months. Billions of dollars remain unpaid to suppliers and yet many of those same suppliers are forced to offer to sell their power at capped prices to an ISO who cannot provide creditworthy buyers.

It is interesting to note that despite all of the non-market interventions, the basic principles of economics 101 are still evident. Prices stabilized when supply and demand returned to balance. During this past summer, demand was reduced by cooler weather and economic factors affecting consumers, and supply was assured through ample termed contracts. In fact, prices began to react to changes in demand before the Commission's mitigation plan was announced.

One other quick observation. The Commission's mitigation plan relies on forcing generators to bid at no more than marginal cost of production and be willing to sell at that marginal cost. Query the reaction of interstate pipelines and regulated utilities, if the Commission would force them to sell their transport or transmission services at the marginal cost of providing those services. There would be a legal revolt that would quickly find its way to the Supreme Court.

Why is it okay to force generators into a position the Commission would not even entertain with respect to other regulated entities.

Now a few comments on the Commission's suggestions for changes to its market mitigation plan. While we have succeeded in eliminating some of the worst features of California's market design, significant problems still remain.

Principal among these is credit. For example, Dynegy alone is still owed over $300 million and that amount increases everyday. When the Commission created its market mitigation plan, it clearly recognized this problem and created a credit premium for sales to California.

Since the underlying credit problem exists today, and for the foreseeable future, just as it did in June when the Commission announced its plan, there is no basis to eliminate the ten percent premium.

It would be far more useful if the Commission would directly address the credit issues in California. If the credit issue can be resolved, then the California premium could be eliminated.

If the Commission is inclined to change its current mitigation plan, two areas of change could be useful.

First, a recalculation of the price caps to reflect increases in gas prices could help avoid a potential situation in which even the variable costs of production for many units exceed the price cap. This could easily occur if gas prices increase substantially through the winter.

In light of historic price swings in natural gas, and the Commission's must-offer policy, the existing Commission system could have the effect of forcing suppliers to sell output at less than their variable cost of production.

It is egregious enough to force suppliers to sell to someone who will not pay for the product delivered. There is no reason to add insult to injury nor heighten suppliers' economic risk by requiring that even if payment is made, that payment be less than the cost of production.

Second, the Commission's mitigation policy should explicitly recognize all variable costs of production. In its current form, the Commission's methodology ignores interstate, intrastate gas transport costs and gas use taxes, which may easily add 50 to 70 cents per mmBtu to the delivered cost of gas. The Commission's methodology ignores start-up costs which can be thousands of dollars per event.

And they're also other charges such as the ISO grid management charge which can be substantial in the coming years.

Finally, while the suggestions made above will help improve the market mitigation plan, the Commission is still left to deal with the fact that its plan imposes price caps which interfere with the development of a true market. The Commission should begin to develop a plan to remove price caps from the western markets as soon as possible. In doing so, the Commission should bear in mind that California has now adopted a bilateral market structure, even if this was not the intended result. California has largely eliminated its reliance on the spot market, although the CDWR purports to be the one to solely determine the reasonableness of prices.

And the purchasing power for California's for consumer is concentrated in only a few players. And finally new generation is slowly being added throughout the west. These conditions were not present at the outset of the price cap policies and present a new phase of the California electric system.

As the Commission moves forward, it should eliminate price caps and focus on ways to encourage customer choice, the benefits of competition, and reliable supply.

Thank you for the opportunity to make these comments, and I'll be glad to answer any questions that you may have.

MR. BARDEE: Thank you, Mr. Lednicky.

Dr. Stern?

DR. STERN: Good afternoon. I'm Gary Stern of Southern California Edison, Director of Market Monitoring. First, as we discuss potential changes to the FERC's June 19th mitigation order, I think we have to recognize that that order has been very successful. We recognize that in fact, because of higher electricity prices and conservation efforts and mild weather, loads have been reduced this summer that certainly makes it easier for the market to operate. Also, we recognize that natural gas prices have come down so that by August of this year, they had returned to the levels that they were at in the prior year, and in fact have dropped below 2000 natural gas prices.

But the fact that some economic conditions have taken some of the pressure off of the market doesn't change the fundamental fact that the mitigation order has been working and is necessary. The must-offer requirement is mitigating the physical withholding of power, and the proxy price limit has mitigated the financial withholding.

Absent the mitigation order, prices I believe strongly would have been higher, and I've done a little bit of analysis to try and support this which was included in the statement I submitted on Friday, and I have some copies here.

What I looked at was some comparable load periods between the summer 2000 and the summer 2001; a week in August, a day in July when the loads were virtually the same, and I found that prices in 2001 were considerably lower than prices in 2000, even if I adjust for changes in gas prices and I've looked at the other factors as well.

I believe that the mitigation order has allowed for the prices to remain low in the summer of 2001 beyond just the fundamental factors that have helped ease some of the pressure in the market. And I think it is critical that we not allow the erosion of this mitigation order that has been so successful in helping restore order to California's market.

With regard to changes around the edges of the order, I think we have to constantly be vigilant and allow the evolution of decisions that we make.

Removing the ten percent credit adder for California makes sense. California does currently have a creditworthy buyer in the Department of Water and Resources and the utilities are moving towards becoming creditworthy buyers.

The fact that there may be some outstanding debts that are being resolved in the past doesn't change the fact that the current situation is that there is a creditworthy buyer.

Now should the mitigated price increase when natural gas prices increase? I think it should. I think to allow the gas price to cause a limit in the proxy price, such that in fact there could be created an incentive for generators to withhold power to see that a new proxy price is set doesn't make sense.

But it also doesn't make sense for that price to stay high when gas prices come down. The concept behind the proxy price was to represent the most costly resource needed to serve load.

And in conjunction with the must-offer requirement, we have created a system that allows us to see what that unit would be and establish a limit based on its costs. Therefore, gas prices moving up or down should be allowed to affect the proxy price.

And the must-offer requirement must be maintained. There have been some implementation issues, some legitimate concerns on the part of sellers about inefficiencies that have been created associated with the must-offer requirement.

I think the ISO, in working with participants in the market, is dealing with those issues and that process is the most effective way to do so, to resolve any issues associated with the must-offer requirement.

But the fundamental tenet of the must-offer requirement must be maintained and the effectiveness of the proxy price, as a mitigation mechanism for financial withholding really only works in conjunction with the limitation on physical withholding for the must-offer requirement.

Finally, there are two other issues not addressed specifically in the announcement for this discussion that are important for effective mitigation of market power as we go forward.

Reporting requirements. More effective reporting requirements really need to be instituted. FERC at this point doesn't really have the data necessary to measure market shares so how can it really effectively monitor the markets?

Bilateral transactions alter market shares and behavior and they should be tracked with more specific reporting information.

As we've said for the past couple of years as analysis of these markets has been conducted, without even knowing fundamentally who has control over how much power it's very difficult to do an effective analysis of behavior in the market.

And then finally, the Mitigation Order, the June 19th Mitigation Order, is set to expire after September 2002.

I think we should recognize early on that a plan to consider its continued necessity should be developed. And if it's determined that in fact its continued use in its current form isn't necessary, that some alternative plan of mitigation should be put in place so that we don't find ourselves exposed in October 2002 to the same kinds of pressures that the California market has seen over the last 18 months.

Well, in just brief response to Mr. Lednicky from Dynegy, if the Mitigation Order really isn't needed, then why is it that the sellers are demanding that it be revoked? If it's not effective? If the market conditions themselves are solving things, then they should consider that the current rules that are in effect won't be binding on their behavior. But I believe that they don't think that's the case. They do believe that the market still has the capability for dysfunction, and it is for this reason that we need to maintain rules such as the FERC put in place on June 19th.

Thank you.

MR. BARDEE: Thank you, Dr. Stern. Dr. Tabors?

DR. TABORS: Yes. Thank you. My name is Richard Tabors. I'm President of Tabors, Caramanis & Associates in Cambridge and a senior lecturer at Massachusetts Institute of Technology.

I'm appearing today on behalf of a group of the members of the Transaction Finality Group who are all market participants in the Pacific Northwest. And what I'd like to do is review some of the things that we perceive as being realities of the market in the West.

The North American Western electric power grid covers one-third of the continental United States and roughly the same proportion of Canada, serves a population of roughly 68.5 million individuals and represents an economy that would be the fourth largest in the world.

Despite these facts, within the written orders of this Commission, the critical characteristics of the power system that drives this region are frequently ignored or misunderstood. Let me look at some of the physical characteristics and the market issues that define the Western Interconnection and clearly differentiate it from both ERCOT and the Eastern Interconnection.

The Western power grid has been designed to be and remains strongly an integrated system both physically and in terms of its market. It is characterized by long AC and DC transmission links that hook together widely disbursed major metropolitan areas with equally widely spread energy resources. Mountain ranges with sparse populations separate the Western coastal areas and Eastern sides of the doughnut-shaped transmission grid. This topology means that the primary concerns for operators in the West are voltage and stability issues that are fundamentally different from the operation of the tightly networked, thermally limited system in the Eastern Interconnection.

Hydro-based generation in the northern reaches of the Peace River system in British Columbia serve load 2,000 miles away in Los Angeles and San Diego at peak times in the spring and the summer. Conversely, the coal and nuclear resources of the Southwest traditionally have helped to serve the energy needs of the Pacific Northwest in the winter and the spring before snow melts. Thermal energy in the winter replaces water supplied to meet summer loads.

In many ways, the hydropower determines the quantity and therefore the market price of energy available in the West. In high water years, energy from hydro in Canada and the Northwest to the U.S. keep prices down, and in the Pacific coastal areas and in the Southwest. In low water years, the process reverses as prices and quantities become dependent on thermal resources.

Hydro plays a second role that is equally significant in influencing the mix of thermal generation. The sheer quantity and with it variability of hydro resources means that peak thermal generation will expect to be called upon far less frequently in the West than it is in the thermal-only systems of the East. Years may pass when peakers are not called to generate a single kilowatt hour. Then will come the summers of 2000 and 2001 when they'll be called upon constantly.

The important yet intermittent role of peakers means their capital costs can only be recovered intermittently and will not be spread evenly across consecutive years.

California plays a pivotal role in Western power markets, but it is not now nor has it ever been the only market in the West. It's simply the most visible market from the perspective of Washington. California is unique in its lack of ability or willingness to provide generation in proportion to population. Its spot-only market structure prevented hedging and long-term contracting. Its structure provided no incentives for demand response. Given the lowest but only one water year in recorded history, California challenged the oldest and acknowledged most robust wholesale electricity market in North America, the West. The market survived and continues to thrive.

Given these characteristics, what are the implications for price mitigation for the winter of 2001 and 2002? The Commissioners and Staff need to recognize that the Western Interconnection is an interdependent market, but that does not mean that it is or should be a single price across that market. Seasonal and geographic differences in supply and demand are the primary definitional attributes of the Western market. Prices in the Northwest forward markets have fallen to below $40 levels. Retail suppliers should have, as they have traditionally in the past, locked in these prices for the bulk of their supply for this winter. California today has sufficient supplies under contract to meet their winter peaking needs.

Setting prices in the winter peaking Northwest based on prices set in the summer peaking California market makes little economic sense. Even with the disruptions caused by the California submarket, the other Western markets have behaved as workable and competitive markets. Again with the exception of California, long-term and short-term trades have continued. Prices have risen and fallen. Energy has been generated, delivered, consumed, and significantly has been paid for with real dollars.

Based on these realities of the Western market, there is little justification for maintaining a price cap for this winter and no justification for basing that price cap on summer conditions in California. Price caps will interfere with existing market mechanisms by discouraging or preventing less costly Southwest energy from flowing to the Northwest this winter because transmission costs may raise delivered energy costs above the cap. Price caps in general discourage new investment in peaking units because they'll be prevented from cost recovery during the hours in which they are needed, and the existing price cap structure creates a level of uncertainty in the market that will force hydro sources in particular to act more conservatively in both the price bid and the quantities made available.

If, given these realities of the Western markets, the Commission chooses to continue to implement some form of price mitigation device, we would urge you to institute some form of circuit-breaker rules set at a regionally appropriate level that reflect the opportunity cost of hydro and thermal resources in the region.

Thank you.

MR. BARDEE: Thank you, Dr. Tabors. Mr. VanLeer?

MR. VANLEER: Thank you. Good afternoon. My name is Steve VanLeer. I represent Duke Energy. I'm the Vice President of Power Marketing for the entire Western part of the United States. Duke has enumerated the issues that it has with the current price mitigation scheme in other filings and comments to the Commission.

Today we would like to focus on simply two aspects of the current price mitigation scheme with the objective in the very specific proposals that we will make relative to these two aspects of price mitigation to provide for supply sufficiency across the entire WSCC but specifically for the Pacific Northwest for this coming winter season, as well, with the objective to provide for price rationalization and equity across the entire WSCC as well.

We first would like to focus on the must-offer provision of the price mitigation scheme. Duke's proposal is to maintain the must-offer aspect of price mitigation but to limit that to times of reserve shortage only. In addition, Duke would propose to create a day-ahead unit commitment market to fortify the must-offer obligation during times of system shortage.

The second area that we would like to focus on and make specific proposal to has to do with the development and implementation of a regional proxy price that would be established and driven in various regions of the WSCC based on delivered gas prices for that region.

In addition, the price would reset, the proxy price would reset in each of the regions based on exceedence up and down of the proxy price of more than 20 percent of the existing threshold price.

With respect to the must-offer proposal, the two key components that Duke proposes are that the must-offer be limited to times of reserve shortage only. This allows the market to operate efficiently without artificial intervention and artificial intervention enters in only at times when it's needed to provide supply sufficiency.

Secondly, limiting to times of reserve shortage encourages solution to the credit crisis that's been enumerated here by other members of this panel.

This proposal also allows the most economical use of limited-run units.

The day-ahead unit commitment market is something that Duke and others have sponsored and proposed to the California ISO and the Commission, and today we strongly encourage the FERC to consider and adopt this mechanism as a way to provide supply sufficiency across the WSCC.

Our proposal requires all generators to participate in the day-ahead unit commitment market and would solve current unit commitment issues surrounding must-offer requirement. In any event, if units are required to stay on line, they must be compensated.

With respect to the second large area of focus and proposal, Duke proposes that a regional proxy price be established for three key regions within the WSCC. That being the Pacific Northwest, Northern California and Southern California Southwest. We propose that the proxy price in each of these regions be based on delivered gas pricing that takes into account transportation and LDC costs. This is more in line with spot production economics and is consistent with current RMR agreement provisions.

Duke further proposes that the proxy price in each one of these regions of the WSCC be allowed to float or change, as has been suggested by some other members of this panel, and that the heat rate be set across the WSCC at 18 which is consistent with the FERC's own March 9th, 2001 proxy market price clearing methodology and reflects the marginal gas unit in the WSCC.

Duke further proposes to remove the 10 percent credit adder and to remove the 85 percent rate multiplier that currently is effective in the price mitigation scheme in the West.

Duke believes that adoption and implementation of these very specific and tangible proposals relative to must-offer and regional proxy price will provide for supply sufficiency across all of the regions of the WSCC and for price rationalization and equity.

Thank you.

MR. BARDEE: Thank you, Mr. VanLeer. Mr. Chabot?

MR. CHABOT: Thank you, Mr. Bardee. My name is Philip Chabot. I'm a partner with McGuire Woods here in Washington, D.C., and I appear today on behalf of the city of Tacoma, Washington, one of the largest municipal electric utilities in that submarket.

I'd like to begin by making reference to the reliability assessment that was released by the Northwest

Power Pool on October 18th. That reliability assessment reached three fundamental conclusions:

First, that in the Pacific Northwest, after meeting loads and required forced outage reserves, little if any margin will remain for the winter season upcoming.

Two, combinations of further reductions to the water supply, inability to fully use hydro system storage for power and/or loss of a major thermal unit may cause a shortage in the upcoming winter.

Three, demand in excess of forecast peak and energy loads might be met by drawing reservoirs below planned levels, but this would expose the area to future reliability risks.

Such conditions could be regarded as favorable, but only in comparison with the absolutely horrendous situation that existed for nearly a year before the implementation of the Commission's West-wide Market Mitigation measures which were formally implemented in June but which you began to see in the Commission's orders that preceded that as part of a continuum in May, June and July.

Now some credit for this improved outlook can be accorded to the fact that approximately 1,000 megawatts of new thermal generation has come on line during 2001 in the submarket. But the sobering reality is that the projection of the reliability assessment is based upon first, an assumption that California will be able to export energy during the winter months, as it has historically done, and unlike it was able to do in the last season; and also on an 18 percent reduction in electric demand that has occurred in part through bona fide energy conservation measures as a result of the scarcities of the last year. But the largest bulk of which have occurred as a result of the complete shutdown of the aluminum industry, which accounts for 58 percent of the 18 percent reduction, as well as major cutbacks in other metal industries, enclosure or cutbacks in other industrial and commercial enterprises.

Moreover, two of the principal factors that contributed to the market dysfunction throughout the West still remain: First, continuing instability in the California markets. And second, the continuing drought in the Pacific Northwest. Again, according to the WSPP report, current water levels and the resulting available energy from hydroelectric reservoirs is approximately 8,900 megawatt months less than the same period last year.

In short, even the most favorable interpretation that can be put on available information suggests that the margin for error or unwelcome circumstance is extremely small and rests upon future conditions about which one can only be uncertain.

The Commission's market mitigation program on the other hand, has worked. From the moment of its effective implementation, the extreme price fluctuations that persisted for nearly a year, fluctuations between 400 and 500 megawatts being routine during that period, were replaced with a regime in which price fluctuations have been collared and remain roughly within a range of $15 per megawatt hour.

It is therefore the position of the city of Tacoma that the Commission market mitigation measures should remain in place during the upcoming winter with the recommendations that were suggested by witness who appeared before the city of Tacoma in the recent Puget Sound proceeding. Specifically, that there be no risk premium and that a localized natural gas price be used.

The elimination of the risk premium for the Pacific Northwest can be supported we believe, that unlike California, everyone in the Pacific Northwest has been paid. There is basically no economic risk that has been established to exist in the Pacific Northwest.

We recommend, therefore, that essentially nothing be done to disturb the existing price equilibrium that has been achieved, that assures that there is no market manipulation; that assures both reasonable prices to the consumer and reasonable profits to investors. We do not support the argument that prices of $400 and $500 and $1,000 a megawatt hour are justified in order to encourage investment. We do not support the kind of perverse economic theories that suggest one can measure electricity through plant shutdowns, employee layoffs, declining GDPs and decreased standards of living.

We believe that is not a coincidence that prices mitigated, and mitigated substantially, the moment the Federal Energy Regulatory Commission showed up as the cop on the beat. Indeed, the view of the current domestic and international business and political climate suggests that it would be the height of folly to risk the existing status quo which has brought measurable benefits to the Pacific Northwest and the entire Western region and to substitute for that an uncertain gamble that Western markets have become fully functional with their underlying defects completely removed in the few months since the Commission orders.

Thank you.

MR. BARDEE: Thank you, Mr. Chabot. At this point I'd like to open the floor to Staff for questions.

MR. ARMSTRONG: Thank you very much, everyone. One of the two proposed changes that went out in the notice had to do with removing the 10 percent creditworthiness adder. The gentleman from Dynegy states that they're in arrears for over ten months' worth of payments. Now some of those months are tied up in the refund proceeding that's before Judge Birchman now. But he made a good comment to tie the removing the 10 percent creditworthiness to having people's past bills being paid. I'd like to hear the panelists' comments if that sounds like it's a good measure to lift the 10 percent adder. Anyone?

MR. VANLEER: From Duke's perspective, the 10 percent credit adder has not met the objective of covering credit risk in the California marketplace. In our opinion, the objective of making California a creditworthy place again to do business keys more on how do you make CDWR a creditworthy or CERs creditworthy counterparty. Other panelists suggested that CERs is a creditworthy counterparty and the supply sides of that equation, I can tell you unequivocally, odes not feel that way until the state is finally successful in issuing bonds to back the purchases of CDWR and to give them credit rating.

MR. ARMSTRONG: So you would keep the 10 percent adder until?

MR. VANLEER: Duke's proposal is to eliminate the 10 percent adder and the 85 percent proxy price cap for nonemergency times. And that's enumerated in the pages of the presentation. I would encourage you to look at those and please ask whatever questions come to mind from that.

MR. BARDEE: Yes, Mr. Wan?

MR. WAN: I don't remember who said this, but one of the panel speakers mentioned that we should separate the past and the future. And I'm a believer that the 10 percent adder has not really done much, similar to Mr. VanLeer's comments. And PG&E being a solvent debtor for the past debt after refunds and all these issues are resolved, plans to pay interest on the outstanding amount.

MR. BARDEE: Dr. Stern?

DR. STERN: The 10 percent credit adder was supposed to represent the prospective risk associated with selling into the market when the buyer may not be creditworthy. It really never did have anything to do with past disputed payments, owed money or anything to that effect. It applies prospectively to sales and it would not make sense to relate it to disputes over past payments unless the same parties were the ones purchasing the power without having resolved the creditworthiness issues.

That's not the case right now. The state has been buying power. The state is, in the form of the Department of Water Resources, they are a creditworthy entity, and the fact that some buyers and sellers have disputes from last year and are owed money really shouldn't affect prospectively the risk associated with participating in the market when the state is the buyer.

MR. LEDNICKY: Could I just add a couple of quick comments there? I mean, from Dynegy's perspective, we don't disagree that there are issues that have arisen in the past, and those can probably be settled separately, although it's nothing as slight as what Dr. Stern would suggest. I mean, there are literally billions of dollars that have not been paid for, and there were billions of dollars that were incurred in costs to produce that, and that's not a small matter, and people are not likely to easily agree on that.

But on a going forward basis, let's not split hairs about DWR or CERs being creditworthy. Whether they are or not, they are reserving for themselves the right to say I will pay this bill, I won't pay that bill. They are doing that on their own without FERC jurisdiction or oversight. And from my perspective, that means I am dealing with a buyer who is not creditworthy. And I really don't care what their credit rating is. I don't get paid, and that's the same effect either way.

And so to the extent that that continues, I mean, that was why my main point in my comment was on the 10 percent adder, facts have not substantially changed from the time that FERC put that policy in place. They are still largely the same today.

Now the heart of the matter, and I think we will all agree with this, the heart of the matter is how do you deal with the credit issues that are outstanding? If you look at Representative Eshoo's list of 43 outstanding issues -- and I've not seen it, but I suspect that a very substantial number of those have at the heart of them credit.

MR. ARMSTRONG: Let me, just before we leave the 10 percent adder, if it was to stay in place going into the winter, would anybody agree that that would present a disincentive for getting the power into the Northwest?

MR. VANLEER: Let me try and fight -- get a grab at that one. And that is, I think quite to the contrary, I don't think it would be a disincentive, but it would effectively raise the bar if you will and would allow additional energy to go in if you left the 10 percent adder on it. You looked blank at me. I'm sorry.

DR. STERN: With the exception of hydropower, other generation sources are supposed to be subject to the must-offer requirement. So this notion that the price limit in the proxy is going to determine who's willing to sell to the Northwest and who is not is assuming that generators other than hydropower are planning on ignoring the must-offer requirement, and I don't think we should be accepting that as a premise.

MR. ARMSTRONG: But your must-offer, if you're not in California, your must-offer says that you can offer to California or Northwest.

DR. STERN: Barring transmission limitations, and there could be a problem during times when the paths are constrained. Having to offer power into the market, whether in California or in the Northwest, should allow for that power to reach its destination. If the destination is Northwest peaks, then the power should be able to get there in the absence of transmission congestion.

MR. TABORS: I think the key element in this is there are other energy limited resources that exist other than hydro, and I think certain emissions limits have been one of those. They've been released in some form or other at this point, but hydro is clearly the swing vote for all of the west, and I think that's major issue at this point.

MR. VANLEER: We would suggest again that supply sufficiency across the different regions of the WSCC will depend on price differentiation and power will not move from the southwestern part of the United States to the Pacific Northwest, where it's needed this winter, unless there is a structure or price differentiation that will cause the energy economically to flow that way.

Duke's proposal again is to have regional proxy cap prices, one of which will be set independently in the Pacific Northwest, based on a Sumas gas price and transportation prices. If you will go back to page 7 -- I'm sorry, page 6 of Duke's presentation, the regional proxy price designations being proposed by Duke are Northern California, which is keyed off of a PG&E citygate daily index gas price and a 40 cent transportation adder, and the Pacific Northwest, to be differentiated, is set on a daily Sumas gas index price, Sumas, Washington, and a 70 cent transportation adder. And it's Duke's strong belief that this price differentiation will allow for supply sufficiency of electricity moving to the point of demand.

MR. GELINAS: Let me try going back over this just one more time. I counted up nine outs and I didn't see anybody on this panel on this panel supporting the ten percent credit adder, and I think that's fair. And I'll throw this out for whoever would like to field it because the notion I'd like to put out is if we were to continue a must-offer that on a going forward basis, it be coupled with a must-pay. And I'd like to throw that out for anyone to field because there seems to be a symmetry there to me.

MR. LEDNICKY: Yes. At the very least, you have to do that. I mean, you can have endless disputes about what the number is, but there at least has to be payment and it has to be timely.

DR. STERN: Yes, we certainly wouldn't dispute that.

MR. VANLEER: We absolutely agree.

MR. GELINAS: It seems like we're spending a lot of time working the pricing but I'm somewhat drawn to the notion that whatever the number is, it's ether unless it's paid.

DR. STERN: To the extent that the Department of Water and Resources is continuing to reserve judgment and therefore reserve payment on power that it considers to be unreasonably priced, I think that issue should be dealt with. They should be required to pay for power at prices that FERC has established as reasonable and perhaps this issue can go away.

Now I don't think a large portion of the dollars that we're talking about are within that gap, but the magnitude may not be important. The fact is I think we all agree that the buyer of the power should pay for the power and do so on a timely fashion.

MR. GELINAS: Mr. Lednicky, if I could ask you to comment on the magnitude of the discretionary payments or whatever you -- is it important just in the abstract? Is it financially significant right now? What kind of numbers are we talking about on a day/in-day/out basis?

MR. LEDNICKY: I would have to go back and dig through, I mean, things sort of naturally fall into several different buckets that are delineated by time period at this point. I mean, there is one period of time that runs from the point in time when utilities stop paying their bills to the ISO and to the PX through January 17th, okay.

And now PG&E and Edison have, over the last month or so, both said that they are responsible for the cost incurred in that period of time, and they are in the process of trying to work out some type of payment arrangement for that period of time.

And I suspect that if you talk with the various suppliers, you'll find that across these time periods I'm going to describe that you will have each supplier with a little different proportion in each situation.

The second time period is from January 18th, let's say, through some time in June, about the time the June 19th order came out. And this is where DWR was supposedly responsible for all of the payments, although if you go back through the paper trail, you will find a lot of circular arguments about yes, we're covering things, but oh, well, here's some details and no, we're not really covering things. And the Commission has before it a number of complaints related to all of that.

Once you get to the market mitigation plan that came about in June, now you have debates of interpretation on well what is that how is that going to be implemented, overlayed with this same problem of CERS having different answers and the ISO having different understandings about what is being covered at any point in time.

In the grand scheme of things, and I will tell you that of the $300 million or so that Dynegy is currently owed, the majority of that is due for the first two buckets, okay. So on an on-going basis, it is not the case that my exposure is, say, a million dollars a day. However, it does very much depend on exactly what the ISO tries to do with our particular units, and particularly as we go into the winter period, if we see increases in gas prices, those costs could become very substantial on a daily basis.

MR. GELINAS: Just one last point here, and I'll let anyone field it. Thanks. I appreciate it very much and then I'll turn it over to someone else.

My question is more dealing from the June 19th order forward. The Commission has pretty much taken your two buckets and put them in a big bucket, and for purposes of today, I was more asking for the June 19th period forward, do we have a significant problem in the area that we're discussing now of call it discretionary payment, call it whatever you would like. That's really what I was interested in. Does anybody have any sense or any observations? Then I'll turn this over to someone else.

DR. STERN: I can again give you my understanding. Since that period of time, there continues to be some amount of money -- I don't believe it is large, that the Department of Water and Resources hasn't accepted as payments that they are required to make, because they may still be exercising their discretion and determining whether the price is reasonable.

And I would suggest even if the magnitude of that isn't very large, that from the standpoint of a seller having uncertainty, the problem may be significant, as we go forward, and in fact it is reasonable to anticipate that one is going to be paid in full for prices that are determined to be just and reasonable by this Agency.

MR. GELINAS: Thank you very much.

MR. MILLER: Let me dwell on another part of the must-offer because I wanted to know, and I'll probably address this to Gary and Fong and Mr. Chabot, if you want to chime in on this, about the discussion Mr. VanLeer brought up about revising the must-offer.

How would you feel about revising a must-offer to a situation when there is a reserve deficiency, however you choose to define that, as opposed to a constant must-offer?

DR. STERN: I can start and this may fall within the concept of the issues on implementation that the ISO is trying to deal with. It's certainly true that when we're in a milder load situation that there are inefficiencies associated with having all units available in a must-offer requirement. The entity that can essentially determine on a day-to-day basis or week-to-week basis how much it anticipates its needs are going to be, in this case for California, is the ISO, and essentially they are trying to establish a system -- I don't know if all the kinks are worked out -- in which they do give waivers for that amount of power that they don't believe will be necessary. The system for giving waivers again may have some continued disputes and may not be as efficient as it should be.

Some recognition that there are times when we're not at peak load and not all units should be made available should be there, that doesn't mean that the underlying requirement to offer power if it is determined by the ISO that it is going to be needed should remain. So we have to be careful in sort of how that must-offer requirement is relaxed so that we don't have the necessity of an emergency before in fact it kicks in, at the same time allowing for units to not have to incur unnecessary expenses and thus impose them on the market when they're not needed.

MR. VANLEER: May I --

MR. MILLER: I think Fong wanted to say something.

MR. WAN: Scott, I actually favor a capacity market. I agree with you that if there are a lot of reserves, it doesn't seem right to have a must-offer proposal. But the difficulty in that is we need to assess market concentration. Even if there are a lot of reserves, we need to see who controls the majority of the market share.

I believe a capacity market where capacity is dedicated to a certain sub-market is a stronger way to approach this. And what I mean by capacity market is something that captures a planning horizon two or three years out, not just six months or monthly product.

MR. VANLEER: Thank you. I would just like to remind everyone that part and parcel to Duke's proposal to limit must-offer to times of system emergency only is the implementation of a day ahead unit commitment market which would be a requirement upon all producers across the entire WSCC, and the purpose of that is to avoid being caught in an emergency situation and to have to scramble in the must-offer process.

The ISO should know at least a day in advance what the system requirements for the following day should be within a reasonable range, and the implementation, part and parcel to the proposal that Duke is making of this day-ahead unit commitment market would allow the ISO to designate in the resource stack those generators that are going to be needed for that following day.

So I think the issue of being caught in an emergency without must-offer requirements is for the most part avoided in that provision.

MR. GELINAS: Steve, are you moving the must-offer 24 hours ahead. Is that sort of what I'm hearing or did I?

MR. VANLEER: I think that's a reasonable way to characterize what we're proposing.

MR. GELINAS: Okay, I see.

MR. MILLER: Let me ask a follow-up, and then

I'll -- because I think some other people want to talk. We're trying to focus on adjustments to the June order and there's a sort of an element of how far you can go to really do incremental market improvements as opposed to just fine-tuning the mitigation order. So bear with me for a moment while I explore something that's a little further afield.

The idea of a day-ahead market and the lack of it in California has proven to be a pretty nettlesome one. And so I'm intrigued by, Steve, your discussion of establishing a day-ahead market. Let me address to anybody who feels they want to chime in on this. How difficult would it be, how soon could we establish a day-ahead market for California? I mean, we're dealing with the west-wide market mitigation approach, but we only have one organized market for the time being.

How difficult would it be to set up a day ahead market? Because it's something I think that we want to be looking at in the future.

MR. VANLEER: Duke has already proposed, together with a number of other suppliers, a day-ahead unit commitment operational scheme that's been presented and discussed to some extent with the ISO. I believe that the members of this Commission also have received that.

We've made specific proposal anyway, and there's been considerable discussion about it. If the Commission would like, we would certainly make that available for your review, and I think the implementation of it would be, compared to the current must-offer requirements, would be fairly easily implemented and carried out.

MR. MILLER: Anybody else?

MR. TABORS: Can I make one comment I guess Scott, and that is that that -- you know, we've spent about an hour and 15 minutes on this panel focused supposedly on the west. But so far we've basically talked about California. So I'm a little concerned about that down the line.

But the second issue is you know you made the statement that there's only one organized market in the west, and I think that's partially true and partially not true because essentially there is a very, very active bilateral market that's existed in the west long before California's markets came into existence. So I think there's an issue, again going back to my initial statements, which is that, you know, from Washington, we seem to think of the west as California and then there are these people sort of scattered around the edge.

And, you know, my client's position is that the people scattered around the edge are the ones who keep the lights on in California. They stretch all the way up to Canada and that California's a mistake maybe, maybe not, it's an event that occurred in the middle of all of this that really has screwed up an otherwise really very nicely functioning market. And so what we're doing here is having a discussion I think about how to fine tune maybe something that deserves some attention but it shouldn't be the be-all and end-all, I don't think, of how we handle the market in the west which is really pretty big. And I think somebody who is following me on has got some pictures but California's still only 40 percent of the market in the west, and you know, if you list them as well always do, California's the seventh largest economy in the world, the west is the fourth largest.

MR. MILLER: I've heard that mentioned before.

MR. LEDNICKY: If I could just offer one comment really in support of some of the things Dr. Tabors is saying. Let's not forget where we came from. And let's not forget the absolutely disaster that we had in California by creating this organized single market/single clearing price/this is how it's going to work. I mean, that clearly did not work in California.

And if you want to look for time-proven market designs, the bilateral design that you see in the rest of the west and in other parts of the country is probably a more stable thing to work with. So it's not to say that it isn't worth putting some effort into trying to organize things and trying to address the issue of reliability, which is fundamentally what we are talking about here, and how do you know that you have the resources committed in the right period of time.

But, I mean, Dynegy would tend more toward a bilateral approach to that than a here-it-is-you-bid-this-way, and the black box is going to spit out an answer to you. So keep that in mind as a matter of context more than anything else.

MR. CHABOT: Mr. Miller, I think is also important to point out to whoever that while there has been a form of a bilateral market in the Pacific Northwest, as a distinct submarket of the western region for some time, the nature of that bilateral market, prior to the advent of market-based rate authority, is substantially different than the market that has evolved since the advent of market-based rate authority.

While transactions occurred both before, during and since market-based rate authority was promulgated, and has been called bilateral because they were essentially some form of arm's length transaction between entities, they were primarily energy exchanges and other forms of bilateral cooperation taking advantage of the very unique generation resources in the region, seasonal capacity exchanges and the like. And it is very different than a market that becomes substantially influenced by the introduction of entities that manage to hold and possess vast quantities of market share and do so strictly on a profit motive, as opposed to the large number of entities that were working before on a cost-based motive.

MR. TABORS: I would have to at least challenge Mr. Chabot in some sense and that is that certainly if you go back to Judge Cintron's outcome of the Pacific Northwest case, and read it carefully or not even carefully, I think it's quite clear that there's an active market in the west in the northwest that seems to have evolved very nicely from one that was energy swaps to one that put dollar signs in it. So I would say it's a very, very active bilateral market.

DR. STERN: Two quick points. One, we used to have a mandatory day-ahead market and it wasn't particularly popular. They call it the Power Exchange.

The other is, and I think you touched upon this Scott, we should be looking at the edges of the June 19th order. What we've got really isn't broken right now. It used to be broken and we put a fix in place. And we've got to be real careful before fundamentally changing that fix because it can be broken again in a hurry, and I don't think we want to take that chance. I haven't heard a lot of strong reason why major changes are necessary. I haven't heard a lot of explanation of where we have real problems in the market today, unreliability or price. So clearly I don't think a major overhaul is the right way to go.

MR. VANLEER: But I would suggest, however, in light of the last comments, that the current mitigation price scheme has not been challenged with respect to movement of energy across the WSCC to the point of greatest need. And it's liable to be challenged this winter in the Pacific Northwest and it's our strong contention that the current structure is flawed for providing for supply sufficiency to the point of need.

MR. BOOTH: To try to satisfy Dr. Tabors about -- not focusing on California -- I wanted to ask a question about the northwest and particularly the concept of having regional proxy prices and I guess my question primarily for Mr. VanLeer but others who are familiar with what's going on up there, how appropriate is a gas-based proxy price for the northwest, given the fact that hydro is so important and is, you know, used a lot for peaking. Is that a good indicator of what the prices would be up there?

MR. VANLEER: I believe it definitely is. If I could ask the members of the Commission Staff to look at page number 5 of Duke's presentation. We did a back cast analysis of regional prices, gas prices, daily gas prices across the WSCC and we particularly wanted to see the winter time which is the time during which the Pacific Northwest typically experiences its peak, and notice that the green line, which represents the northwest Sumas gas daily price frequently exceeds all other gas index prices across the western United States. Gas is definitely the marginal generation fuel in the WSCC and the Pacific Northwest.

So we believe that that because the gas price in the Pacific Northwest typically exceeds all other gas prices across the WSCC, that unless there is price differentiation to the Pacific Northwest in the proxy price, there could be insufficient supply and movement to that region.

MR. BOOTH: I notice on page six in addition to the Sumas Index, you're adding a transportation adder. Is that a gas transportation adder?

MR. VANLEER: Yes, it is. And for each of the three proxy prices that we're proposing, the transportation adder is different because of the location of the different indexes that we're proposing to use. Some are into the interstate pipeline system, some are into the LDC, and so the transportation adder is different for the different regions.

MR. BOOTH: I'm not as familiar with gas transportation but is the transportation adder higher in the northwest than it would be to a citygate in California?

MR. VANLEER: It is, Mr. Booth. For deliveries at Sumas, Washington, simply because those deliveries are for gas delivered into Northwest Pipeline's main line system. In addition to that transportation charge, the assumption is that you would have a charge on an LDC as well. And that's how you result in a higher transportation adder for the Pacific Northwest.

MR. BOOTH: Any other comments?

MR. CHABOT: We support the concept that the pricing should be reflective of conditions in the individual submarkets as opposed to the region as a whole. That's the first part of your question.

The second part was with respect to natural gas. We believe that it may not be the best measure but it's probably the most efficient and easiest measure to apply, and it's consistent with the concept and policies that FERC embodied in its May, June and July orders okay?

MR. TABORS: Just being difficult, I think we agree totally that what else is new? We agree totally --

MR. BOOTH: I'd be disappointed if it were otherwise.

MR. TABORS: I agree totally that it is necessary to have a regionally differentiated price if you're going to play the price game in that sense. But I would point out that natural gas, because it is not necessarily the marginal fuel for electricity generation and it has very little to do with the opportunity cost of what is frequently the marginal fuel, which is water, so I think one of the issues at stake is that opportunity cost plays a major role in the Pacific Northwest, and picking a daily gas price to get a ceiling doesn't capture what the value of that water will be at some point in the future. And I think that's what's missing in this whole debate at the moment is the realization that to be able to peg a price has nothing to do with what the market or anybody else has an expectation of what the value is at some point down the line.

So we're working kind of a price today against a value measure down the line, and this is not an unknown phenomenon in the hydro business. This is the way you have to think about hydro day in and day out. So I think that's the only concern I have about saying natural gas price at Sumas is the right one. It clearly is the right one given that you're going to use natural gas, but I would argue that's the wrong approach.

MR. BOOTH: Mr. Lednicky?

MR. LEDNICKY: I would again make a comment similar to that. If we pull ourselves out of the details here, it seems to me that the real question is, where are we trying to be in one year or two years or five years. If the point of this exercise is to constantly refine price caps, so that they are calculated instantaneously for every little unit that's out there, that's fine. I mean, you can go from one price cap to three price caps to 300 price caps. But again it seems to me that that ought not be the goal that we're looking for, and we can't have this mind set that says well, the market doesn't work so we'll control it until it works. I mean, that won't happen. You can't say I don't have a market so I'm going to interfere until I get one. I mean, it won't.

So as we go through the analysis of this, I go back, the reason I tried to offer in my comments some context about what's going on is to try to point out that we need to think about where we're trying to go, not how to refine some particular formula. And that is something that has to be done at some point in time.

MR. BOOTH: I had one last question. Mr. VanLeer, you made a reference in your discussion about the must-offer, your optional must-offer proposal about that if you were to go to what you were suggesting, just doing it in emergency situations, it would help out the credit adder or creditworthiness. I didn't quite follow what you were saying there. Could you explain that a little more?

MR. VANLEER: I simply was saying that because the market would be allowed to work as the market naturally works, except for situations of system supply deficiency, that buyers and sellers would naturally adjust their activities to the credit environment.

MR. BARDEE: I had a question for the panel. Over the last year or so, with all the issues that have arisen in California, the Commission end up with the price mitigation we have now before us which compared to the price caps in the eastern ISOs is more complex. And one of the panelists we'll hear from a little later suggests that in certain circumstances, it might be more appropriate to just switch to a fixed number like they have in the eastern ISOs. There it's a thousand dollars.

The question I have is what do you all think of that either for some parts of the western U.S. or the whole U.S. going forward as opposed to worrying about what's behind us now.

DR. STERN: Well just to remind folks where we came from, in California in the year 2000, we had a fixed price cap. It was a 750 and we spent a billion dollars on power in a week. We reduced it to 500 and we reduced the pace at which dollars left buyers' hands.

We've reduced it down to $2.50 and we've pegged a price of $2.50, even though gas prices were running around $3.00 $4.00, $4.50 or whatever at the time.

We've had a fixed price in California and no other form of mitigation to go along with it, and it didn't work. And really, one of the reasons we are here today is because some other form of mitigation had to be put in place, in place of that one. The soft cap approach that was put in place for the winter of this last year didn't work, and now we have something that maybe it hasn't been fully tested, but so far, we haven't had the same kind of problems. And so I think before we conclude that we should jump to something else in fact we've tried and has failed before in California, then I think we ought to see if this one won't actually work.

MR. MILLER: Gary, I take what you mean on that, but presumably, you'd be in the same situation on a going forward basis that the entities in the East are now that there wouldn't be impediments, however you define them, to you being fully protected in the forward market or however you choose to, you know, manage your portfolio.

I understand what you're saying about the year 2000 meltdown. But I ask you to respond to Mike's question, thinking in terms of your being free to manage your needs as you see fit.

DR. STERN: Clearly, there were a confluence of events that contributed to the situation we faced in 2000. But I think that among those -- which include the inability to sell power forward, a lack of effective price signal to consumers, et cetera, high gas prices, the emissions costs -- but included among those was an ineffective market power mitigation. And I think that to assume that going back to that because other conditions have changed ignores that fundamental fact.

MR. TABORS: I guess let me argue with a part of it anyway, and that is that I think Mr. Bardee's question is a good one, and the question is why not? And certainly for everybody who operates in the Eastern market, the so-called circuit breaker, which is what I suggested in my testimony, makes good sense, seems to work, and it works because the market seems to have spread itself around between long-term contracts and spot contracts in a way that makes sense.

Clearly, the Eastern United States has no water. I mean, it falls from the sky, but it doesn't go behind dams. So that's not an element of the market and so not an element of the variability in that market either. The demand in the East didn't grow like the demand in the West did. The east got generation. The West decided not to bother letting any get built. I mean, you could go on and on and on and ask yourself, you know, have we worked our way through that system? And Mr. Chabot listed 1,000 megawatts of new generating capacity. I don't know, my notes indicate 10,000 megawatts of new generating capacity in the West in the last 12 months.

So I think these are the forces that are underway that aim you toward something that says I don't think you need that type of price cap that the higher one would be not only functional but would actually fulfill the objectives of FERC of getting a functional and efficient market running rather than kind of a control system and operation.

MR. CHABOT: I think, as the Commission has said in the past, the purpose of using the marginal dispatch price is to as closely as possible to simulate a market base rate, and the price of marginal dispatch varies with conditions. And so we think that the formula should also vary with conditions.

I would also point out, endorse the concept that the absolute fixed prices don't work. I think that's been demonstrated, and I don't they're fair for either the generators or the consumers.

One slight note with respect to Eastern markets. There are of course areas of the East that are susceptible to hydrologic influence. Certainly the New York Power Authority region and as well as TVA, obviously. But certainly not also to the extent that the Pacific Northwest is.

MR. WAN: A number of things went wrong last year to lead to what we have seen. If you take a look at it, somebody mentioned earlier that we had tremendous demand growth in California. We also have to remember that we did not allow consumers to respond according to that.

Gas prices, whether there was manipulation or not we'll never know. In terms of generation, whether there was physical or economic withholding, we probably will never know.

I think the biggest piece is the contract mix that was mentioned earlier. With all the IOUs forced to go to the spot market, there was no set of rules out there that could have prevented the disaster that we faced.

As we go forward, if we have a balanced portfolio for the buying entities, I think a lot of the problems would be solved.

MR. LEDNICKY: And I was just going to quickly say, assuming that the goal of all of this is no price caps, then the more you can simplify the system and the more you can wean yourself away from the price caps from the very beginning rather than making it more and more difficult then building a whole bureaucracy around that, then the better off you're going to be. And the world is very clearly different today in many, many respects than it was a year ago.

And so we ought to learn from what happened last year, and we have, and we have changed. As I said, we've taken out many of the worst elements of the market and we are operating in a different context today.

MR. VANLEER: Lest Duke's position be misunderstood with respect to the position that Mr. Lednicky has enumerated, the more free market environment that we can operate in, the better. And if we thought that we could come and convince this Commission today to remove all price caps and to allow the market to work, that would be our position of choice.

We just weren't sure that that was a rope we were willing to push today. And we came here on the assumption that the price mitigation for the West was the natural assumption. But with respect to your, specifically to your question, the more free market environment that we have to operate in, the better.

MR. ARMSTRONG: I'd like to follow up on Mike's question and something, Lynn, that you said about being less intrusive. We had two proposed changes in our notice, and we had a real good discussion about the 10 percent adder. And I think you've helped me understand everybody's viewpoint on that.

The other proposed modification was that we just take the gas input and when it rises 10 percent as an example, we would recalculate the proxy price, and holding all the other inputs the same, it would go to a new price of about $104.

Now the $92 price cap has stayed in place all through the summer and the prices at COB and Mid-Columbia and Palo Verde haven't been hovering at $92. They've been, according to some of these printouts, fluctuating between $60 and $80 and maybe even some hours lower than that. So it's a ceiling price that looks like the market forces are working where it's not staying at 92, and if it goes to 100, stays at 104. And Dr. Stern, you had said that there should be symmetry. And Mr. VanLeer's printout, page 9, you would show when the prices fluctuate by 20 percent, they would go up and down.

I'd like to hear the panelists comment on the adjustment that we proposed in the NOPR, just keeping it with just an adjustment up if gas prices do rise from the $92, which was calculated at $6.64, and it increases by 10 percent to about $7.20.

MR. WAN: I think my remarks agree with adjusting the prices up when gas prices go up. We would like to see a similar adjustment down when the gas prices go down.

DR. STERN: Just following up on the remarks I made earlier, first of all, of course, with a $6.60 gas price as the starting point, I'm certainly hoping that in fact the conditions where that gas price rising above that level isn't something that we're likely to see anytime soon. But I've learned that we can't predict these things as well as we'd like, and we cannot assume that it's not going to happen.

If it does happen, one of the reasons I believe that we should allow the proxy to go up is if you're selling into the market, your opportunities are to, if your costs rise to such a price, you're going to have to bid above the proxy and go through this process of justification of costs and all that, which would probably allow you to ultimately recover those costs. Or, more appropriately, the proxy price would go up to match the increase in gas price.

And you don't want to put the sellers in a situation where the only way they can see the proxy price go up is if we reach a Stage One emergency condition because now we've created this terrible conflict. We have the must-offer requirement on the one hand, but potentially not compensatory pricing on the other, and they're sort of encouraged, they'd really like to see a Stage One so the cap resets itself, the proxy price resets itself.

That doesn't really make sense, and therefore, I support the idea of having the proxy price allowed to move up. But the idea that somehow then if the gas price spikes up -- you might recall last December, the gas price spiked up to $60. Sixty dollars a mmBtu. And if we allow the proxy price to go up but not come back down, we could effectively eliminate the whole design of having a proxy price.

So there has to be some ability for a restoration to a rational proxy price if gas prices go up, because gas prices presumably will also come back down.

MR. TABORS: I guess I just have to make the same comment I made a minute ago, and that is, for an awful lot of the energy that flows in the West, the price of natural gas is totally irrelevant. And unless you're willing to look forward at the opportunity cost of natural gas that really reflects the opportunity cost of the thermal energy that goes into the hydro fillback or goes forward for anybody else who has a limited energy facility, whether it be thermal or hydro, you're really only capturing one element of the market, and it's very convenient, but it's an awful lot like the drunk looking for his keys under the light and when asked the question, did you lose your keys? The answer is yes. And, where did you lose them? Well, over there. Why are you looking here? Well, I can see better over here. And I always worry about finding very simple solutions or paradigms for something that's a much more complex market issue and has a very real impact on long-term elements in the market.

DR. STERN: Let me add one other, just an interesting note. It's not really a recommendation here. But this is something that Angelle Shefford I think pointed out at the RTO workshop about ten days ago. We found ourselves in an unusual situation with our proxy price in California because since it was set at the $92 level, gas prices have come down and it's gotten to the point where if in fact we hit a Stage One emergency again, there would be a substantial resetting down of that proxy price. And that's created in a sense a very effective incentive for generation that we haven't really seen in this market before, generation that's strongly incentive to ensure that we don't find ourselves in emergency situations, in the same way that utilities used to operate prior to deregulation. And I think it's actually been very effective at providing reliability.

I'm not sure exactly how we can align those incentives as effectively in the future. But I will say that we're observing something that we should learn from.

MR. LEDNICKY: To the extent that you believe in conspiracy theories and that absent some type of rigid price cap, the sky will go to the moon, well I suppose that's all true, and I'm not sure that there's that much empirical evidence to say that that's the world that we're living in now.

And again, I won't repeat the comments I've made before, but I think what you ought to be thinking about in terms of price caps and whether they're moving up and down and how dynamic they are ought to be from the perspective of where do you want to be a year from now or two years from now as opposed to the exact mechanic of how it might work today or tomorrow.

MR. CHABOT: I would like to again endorse the concept that the value of water is certainly one of the key elements that should be taken into account in the Pacific Northwest if you can. Valuing water, however, I suspect gets pretty difficult, especially when you're -- pretty difficult when you're looking at it in a reservoir and trying to determine what its long-term use is going to be.

I noticed Chairman Wood sitting against the wall, and it reminds me that the situation with respect to natural gas pricing is not dissimilar I think to a problem that the Texas Commission had with respect to the natural gas flowthrough for Entergy several years back. And the solution that was created for that, to the best of my recollection, was that there was a periodic review and if necessary an adjustment, as well as a percentage adjustment that triggered in the event that there was a rise one way or another, and that there was symmetry. And that those three worked fairly well to solve the problem of the energy charge passthrough.

MR. GELINAS: Let me try and wrap this up if I could. And I've heard, you know, some placeholders. Lynn, I heard you obviously you're very concerned, and rightfully so, that we ought to keep our eye on how we're going to get ourselves out of price controls rather than focusing entirely on how to fine tune them. Although I will say the immediate problem unfortunately seems a little bit more how to fine tune them.

Steve, I heard your statement. You came here with sort of a realistic approach that some sort of price mitigation was going to be in place. And I don't know, that's probably a fair -- I understand you're trying to get those prices as high as possible, given the fact that there is some mitigation, to capture as many market symmetries as you can.

But with respect to -- with all those caveats, I think with everybody except Dr. Tabors, which I think has put out some sort of circuit breaker based on opportunity costs theory which I'll leave aside for a minute, I heard unanimity from everybody else on this panel on the core concept, although you have slightly different ways of doing it, that if we're going to keep some sort of mitigation, then we need to track gas prices in some fashion. Some have proposed regional or whatever, and they need to come up as well as down.

And Dr. Stern, I think I was captured by your analogy that if we go to $60 gas, we'd be back at $1,000 price cap very soon, and that might stick. But have I pretty well -- have I got everybody's position fairly well on that?

(Nods in the affirmative.)

MR. GELINAS: No disagreements? And everybody is really supportive of dropping the 10 percent credit adder. I think that's uniform across the table. And I think those were the two main issues we had. Does anybody else have any questions or -- Mike?

MR. BARDEE: I'd like to thank our panelists, then. SUggest that we take a short break and resume back at five minutes before the hour

(Recess.)

MR. BARDEE: Let's go ahead and get started. Mr. Comnes will be joining us momentarily I'm sure. Let me introduce the panelists.

Starting on the left we have Mr. Bill Julian for the California Public Utilities Commission. Mike Naeve, former Commissioner for this agency, representing Portland General. Mr. Dejean Sobajic on behalf of the Electric Power Research Institute. Mr. Mark Tallman for Pacificorp and

Pacificorp Power Marketing. Mr. Brian Theaker for the California ISO. And to be joining us soon, Mr. Alan Comnes for Enron Power Marketing.

Mr. Comnes, if you could begin, please.

MR. COMNES: Good afternoon. I'm Alan Comnes, Director of Government Affairs with Enron Corporation.

I support Enron's power marketing affiliate, Enron Power Marketing, Incorporated, or EPMI. EPMI has operated as a power marketer in the Western Interconnection since 1994.

Today we operate in all major markets in the interconnection.

EPMI does not own an appreciable amount of generation in the West and as a marketer serves both customers and suppliers. We trade both physical power and financial hedges and trade power both on a short and long-term basis.

EPMI is a member of the Transaction Finality Group or TFG. And TFG has sponsored Dr. Tabors earlier today. As a marketer with a broad scope, however, EPMI requested to directly participate today to assist the Commission in understanding the implications of continuing the West-wide cap.

I work on EPMI's trading floor in Portland, Oregon and have had a daily, first-hand knowledge of the

Commission's cap as it has affected markets thus far.

I'll have just a couple of slides with today's talk.

(Slide.)

MR. COMNES: Dr. Tabors has presented to you information on how the West operates as an integrated market throughout the West. And he emphasized the importance of opportunity costs of hydroelectric power in defining efficient, competitive prices. And I'd very much like to support Dr. Tabors' comments in this regard.

This chart, which I've got up now, I'm not sure why it's -- well, let me just move it here.

(Pause.)

This chart compares loads with California and the rest of the West and hydrocapacity in the West to all other capacity, thermal capacity, and shows that 41 percent of the capacity in the West is hydroelectric.

So when people talk about the importance of opportunity costs and the difficulties of defining a competitive price based on gas prices, I think a slide like this really hits it home, and that's why we supported Dr. Tabors' comments today.

However, the message I really want to deliver today is that the need for the Commission to provide consistent rules to restore confidence in the marketplace.

Consider that so far, the Commission's price mitigation in California and the West has had seven formulas in the past 18 months.

The current price mitigation for the entire Western Interconnection is controlled by the California ISO, which is in turn controlled by the governor of California.

The current mitigation can change in any hour and cannot be known in advance with certainty. In that regard, if the California ISO were to declare a Stage One emergency for a full hour today, the price ceiling for the Western Interconnection would fall to $28. This price level would be far too low to provide reliable supplies to the grid this winter.

The Commission's must-offer rules, along with its decisions denying cost recovery of above proxy transactions send the message that generating resources, especially peaking resources, will not be compensated for in the future.

Uncertainty of this kind placed on the market in the last 18 months has increased risk premiums and transaction costs. I might also add it led to blackouts in Nevada on July 2nd.

The current mitigation mechanism has been more or less pegged at $92 since June 21st. For only a handful of hours on a couple of days have market prices been at or near the cap.

Thus the current cap has actually had little effect in controlling prices. In that regard, I do take exception with some of the positions presented today. Instead, market fundamentals have caused a substantial price drop seen beginning in late May.

The changes in market fundamentals are well known. Price-induced demand response. Ten thousand megawatts of new generation capacity installed since last summer. Clearer than normal weather in parts of the West and an economic downturn.

(Slide.)

MR. COMNES: This chart shows installed capacity in the last year, and you can see that 9,000 megawatts has come on line just since May.

And I should also note that in RTO Week, it was mentioned there was a GAO study and some investment research firm studies that indicated the price drops in the West have been due to the market fundamentals and not the price cap.

Although the cap may serve to limit price spikes in the future, it will degrade reliability, thwart the development of peaking resources and delay the day that meaningful, on-peak demand responsiveness programs will finally be created in California.

Thus, given that the market has functioned well in responding to changes in fundamentals, EPMI recommends that the Commission remove the West-wide mitigation altogether.

However, to the extent the Commission leaves any West-wide mitigation in place, the Commission should make the cap consistent West-wide and remove any control of it by the California ISO. The best way to do this is to adopt a high damage control or circuit breaker cap of $1,000 or similar level.

This would be a cap similar to the circuit breaker caps that are in place, to my understanding at ERCOT, the New England ISO, PJM and the New York ISO.

If the Commission must retain a lower cap that is likely to be low cost, below cost in many hours, you must provide an escape valve for gas prices. I think you've heard that today. In other words, you must make the cap equal to a higher of a fixed nominal level or a gas-based index.

Further, any gas-based index must be based on daily gas prices, not month-ahead gas prices. At this point, prices will only rise this winter above $92 due to a supply disruption or weather event.

Such price excursions are short-term in nature and month-ahead gas prices will not properly reflect opportunity costs on such days.

I might also add that compared to the proposals that were presented in the first panel, we would strongly recommend one gas-based index in the West.

You might want to set it at the highest of a regional gas price such as Sumas times a marginal heat rate. You might have three say competing calculations and the highest of all the three would set the cap.

But I strongly recommend against regionally differentiated price caps, and I'd be glad to answer more about that in the Q&A.

The proposal on the workshop notice, therefore, isn't flawed, that it keeps the California ISO in control of the West-wide price cap and uses a monthly gas price.

Finally, I would like to make a point about what would really bring reliability in the West. EPMI recognizes that the concern over the current cap is that it puts reliability of customers residing in winter peaking systems at risk.

The current cap will make it difficult to induce supply especially from hydroelectric and out-of-area resources should a price spike occur.

However, true improvement to reliability in the Pacific Northwest and the rest of the West will only come via the aggressive pursuit of an independent, integrated RTO.

The California ISO still has unilateral control of export capacity to the Pacific Northwest from California and the Desert Southwest.

Even if the Commission wrestles control of the cap from the California ISO, the California ISO will still be able to manipulate the market via its control of export capacity to the Pacific Northwest.

This is not an idle threat. The Pacific Northwest experienced a precipitous drop in south to north export capacity beginning last winter as a result of unilateral decisions made by the California ISO.

(Chart.)

What this chart shows is export capacity into the

Pacific Northwest from California at Cobb. Based on our market research team, this is the marginal transport path to the Pacific Northwest this winter.

You can see that for reasons that the ISO has claimed to be due to Path 15 reliability, they have drastically cut the amount of capacity available to the Northwest.

It is this kind of capacity reduction that threatens reliability more than the level of the price caps at this point.

So only return to an independent board governance of the California ISO and the creation of a single Western RTO or, alternatively, seamless coordination between the California ISO and the rest of the West, will the Pacific Northwest get the reliability and price stability that the parties seek here today.

Thank you.

MR. BARDEE: Thank you, Mr. Comnes.

Mr. Julian?

MR. JULIAN: On behalf of President Loretta Lynch of the California Public Utilities Commission, I express our appreciation for the invitation to appear and participate in this panel.

California has begun the arduous process of recovery from the energy debacle that has afflicted it for the past 18 months.

The State has raised retail electric rates an average of 4 cents per kilowatt hour, nearly 40 percent since January of this year.

We have reduced peak demand during Summer 2001 by nearly 4000 megawatts from Summer 2000 levels, nearly a 9 percent reduction in absolute terms.

We have added nearly 3000 megawatts of new in-State generation in the past 12 months.

We have established the California Department of Water Resources as the largest buyer in wholesale power markets for energy to meet load in the State, which spent over $11 billion in the past 8 months and has entered into arrangements to spend as much as $44 billion over the next 15 years.

We have created a new public power authority with the ability to spend up to $5 billion on new energy supply projects.

We have expedited permitting and construction of critical gas and electric delivery infrastructure within the State.

We have undertaken significant investigations and litigation to recover monies unlawfully demanded and paid for energy over the last 18 months.

The goal of these efforts is to assure the people and businesses of California that their electric service will remain reliable and fairly priced; that the repeated threats of rolling blackouts and price spikes will be eliminated; and that electric costs will return to reasonable and affordable levels.

In order to accomplish this, the State intends to restore the ability of the investor-owned utilities to meet their obligation to serve, and ultimately to reduce the role of the State in providing electric energy to retail consumers over time.

The CPUC has recently resolved federal litigation with Southern California Edison in a manner designed to restore that utility's credit pay its debts, and enable it to resume electric energy procurement.

The CPUC has issued a series of orders intended to reduce a procurement-related balancing account for San Diego Gas and Electric as a prelude to its resuming its energy supply activities.

Along with other agencies of State Government, it is addressing the issues posed by the Chapter 11 proceeding of Pacific Gas and Electric to resolve that utility's credit issues.

And, on Thursday the [CPUC] commission commenced a proceeding to establish a framework for electric energy procurement for the investor-owned utilities going forward.

In order for these initiatives to succeed in their purpose, it is essential that the wholesale electric energy markets remain stable and predictable over at least the next 18 months so that the utilities can in fact get their debts paid, resume their procurement roles, and participate again in wholesale power supply arrangements.

Each of these initiatives ultimately involves fully exposing retail consumers to the costs of electric supply arrangements. The CPUC is committed to assuring that those costs are just and reasonable.

And the CPUC views the FERC as an essential partner in these efforts.

The FERC Orders of April 26th, and especially June 19th, have played an important role--perhaps the crucial role--in creating and sustaining a more stable atmosphere in short-term wholesale supply arrangements over the past few months since their issuance.

Keeping the price mitigation measures contained in those orders in place through the period the CPUC has identified as necessary for the rehabilitation of utility credit--an outside date of December 31,2003 but perhaps earlier depending on the speed with which debts are paid--will be critical to bringing the wholesale markets back to a sense of order and predictability.

The CPUC shares the basic perspective of those orders that predictable prices, predictable dispatch regimes, and reducing reliance on spot and real-time markets to serve retail load are essential elements of recovery.

While perhaps not agreeing on every detail, the CPUC supports fully the general direction of the price mitigation orders and suggests that they be kept in place until the load-serving entities in California are fully rehabilitated.

I must say, I did not expect to be agreeing with the speaker from Dynegy but I think his basic point that we need to be focused on the objectives that we are seeking to serve is a paramount consideration. And for the CPUC it is rehabilitation of utility credit and restoration of the utilities as load-serving entities capable of fully participating that is the critical issue.

Our efforts are, frankly, at a very delicate stage and are best served by stability.

The critical elements of April 26th and June 19th that must be kept in place are:

The Must-Offer Requirements for California generation as an effective anecdote for withholding.

Elimination of regional arbitrage opportunities--megawatt laundering--including consistent application and enforcement of the price-mitigation regime throughout the region.

Requiring marketers to be price takers to avoid transitory market power.

And effective price caps based on a robust, transparent price established through the California ISO.

There are details of the price cap calculation that we believe warrant further consideration. The 10 percent creditworthiness adder for sales into California is not well supported in the June 19th decision and is contrary to the State's extensive efforts, including advancing substantial monies from the State's General Fund to pay current costs on a current basis.

We have heard from the earlier panel suggesting that the 10 percent creditworthiness adder may not be functional. That certainly is in accord with the PUC's position.

The CPUC supports the FERC's continued use of the ISO market clearing price as the basis for the mitigated price, and would oppose any attempt to base price mitigation on bilateral transactions involving less efficient units than those bid on the margin in California, as proposed by some marketers. This approach would add another element of uncertainty and instability, which is what we were seeking to avoid.

If each organization stays its course, the consistent and parallel paths of the CPUC and the FERC may lead to restoring confidence in the wholesale power markets over time, and may lead to restoring the utility's role in those markets.

However, there are opportunities for joint and coordinated action of California and FERC that will improve the chances that the price mitigation orders can succeed.

These include:

Coordination of generation facility maintenance and outage scheduling, important both for assuring reliability of supply and mitigating the exercise of market power and the price excursions that are both the symptom and the disease.

Coordination of remedial investigations and market monitoring activities, including sharing of information.

Coordination of market reform efforts in a manner that respects the state's responsibility for retail end-use service, and the FERC's responsibility for robust competitive wholesale energy markets.

Each of these measures will strengthen our mutual ability to limit withholding of energy and the threat of supply disruption. Each of these measures poses important challenges under the Federalism structure of the Federal Power Act. The creative use of joint boards and information sharing under Section 209 would be an effective way of bringing both State and Federal resources to bear on our common problems.

Mr. Stern's suggestion that strengthened market monitoring and information development is an important element was a point that was sort of lost in the last panel, but I want to emphasize it for this panel.

Thank you.

MR. BARDEE: Thank you, Mr. Julian.

Mr. Naeve?

MR. NAEVE: Thank you very much, Mike.

As Mike previously mentioned, I am appearing on behalf of Portland General Electric Company. I also am appearing on behalf of the Vista Corporation. Both are utilities of the Pacific Northwest. Both share the concern about reliability this winter.

As Mr. Chabot mentioned, if conditions are acceptable this winter, we can make it through the winter without reliability issues.

On the other hand, very cold weather, particularly for a protracted period of time, loss of units, a variety of other factors could lead to conditions where we have an inadequacy of supply this winter. We are concerned about price, but we are equally concerned about adequacy of supply.

We have a couple of concerns with the current price caps as they apply to the Pacific Northwest.

One is a short-term concern, and the second is a long-term concern. Let me begin with the short-term concern.

The particular level of prices established under the price cap scenario is not connected to market conditions in the Pacific Northwest. We are a winter-peaking region; California is a summer-peaking region.

They are based on 85 percent of the proxy price set this summer in California. It may turn out that that price is perfectly adequate for inducing supplies into the region under certain load conditions to meet our needs.

The opposite could be the case. It could be that it is inadequate for bringing forth sufficient supplies.

The point is, it is completely arbitrary. Normally when an agency sets price caps, the price caps typically do turn out to be arbitrary and they are either too high or too low. We don't know yet whether they will be too high or too low this summer.

I certainly was at this agency at a time when we set gas prices, and we always set them wrong. We set them too high and we brought forth too many supplies. We set them too low, we created shortages. That could happen this winter.

Secondly, the caps are based on the cost of thermal units. Even if we were to make adjustments to these caps to reflect changes in gas prices for thermal units, it could well be that the thermal unit was not the marginal unit. And indeed, very severe shortage of hydro supplies will be the swing supplies. They'll be the marginal supplies.

Prices established based on the cost of thermal unit may not be adequate to induce hydro suppliers to release their water and meet our needs.

Keep in mind that hydro supplies are somewhat tight at this stage. We really will not know during the peak of the winter what the availability of hydro supplies will be next year because we won't know how large the snowpack is in December and January until after the fact. We will know in February and March and April how large the snowpack is, but in December and January and maybe early February we won't have a good appreciation of what hydro resources will be next year.

So consequently, if you are a hydro supplier during the early parts of the winter, and even the mid-winter and the deepest part of the winter, you may need to preserve those hydro supplies for anticipated needs next year.

You are going to be very cautious to let them go. And prices based on natural gas may not be sufficient for you to release a valuable resource that you may need sometime in the near future. So you may need sufficiently higher supplies, and you may need--you obviously will need price certainty as well.

Furthermore, we are not just talking about hydro suppliers in the Pacific Northwest, because in the Pacific Northwest utilities there will be husbanding their hydro resources to meet their needs in the summer. But also the same effect will be applied to hydro suppliers in California, hydro suppliers in British Columbia, and elsewhere. And indeed, if we do have a severe winter we will need those hydro supplies to meet our peak load.

Our long-term concern is that price caps based on the California model do not provide adequate incentives for peaking units that may only run a few hours or days a year.

The price caps are based on units that--they are based on the marginal cost of running these units with high heat rates, and if you have a peaking unit with a high heat rate your marginal cost may not be sufficient to allow you to recover your fixed investment.

Not only that, but it was pointed out by the earlier panel, in the Pacific Northwest hydro--pardon me, peaking units have a special problem. That is, because hydro resources are available many years, and other years they are not available, in those years when hydro resources are available, peaking units may not run at all.

So not only may you run a very few hours in a year, many years you may not run at all. So consequently the incentives and the disincentives for the construction of peaking units in the Pacific Northwest are especially profound.

Our recommendations are this:

We would recommend that during this winter period the Commission in effect lift the price caps on the Western markets. Now this can be done in a variety of stages.

You can lift them all together.

You can lift them just in the markets outside California.

You can lift them subject to a circuit breaker.

There are a variety of ways this can be done, but we think the continuation of the price caps this winter for the reasons I have previously mentioned could leave to supply disruptions.

Another variation would be that you could lift the price caps only in situations where you experience a supply deficiency outside of California and then lift the price caps.

There are a variety of ways to approach this. Certainly if we do have a reserve deficiency situation outside of California, by definition prices have not been sufficiently high to induce adequate supplies.

In any situation where the Commission were to choose to life prices or life prices subject to a circuit breaker, it certainly could retain the authority, as it has today, to reimpose those price caps if it determines that markets turn out to be dysfunctional.

I suspect that markets will not be dysfunctional, and there are a variety of reasons.

First, there no longer is an over-reliance on the spot market. Keep in mind, these price caps apply only to the spot market. Certainly there never was an over-reliance on the sport market in the Pacific Northwest.

Today, there is no longer an over-reliance on the spot market in California, either.

We have seen from a variety of the slides presented today that the markets appear to be functioning well in California. We have a ceiling price, but prices have floated below that ceiling price for quite some time largely due to market forces: more supply, less demand.

And as a general rule, I think based on recently experience that we can probably safely resort to either no price cap or some sort of circuit breaker price and see adequate supplies.

Our other recommendation would be: If the Commission were to lift the price caps subject to a circuit breaker or not for a period of time, that they make it clear that the prices charged during that period are final prices; that the sellers are not subject to being second-guessed after the fact.

If they are subject to being second-guessed, I think it would not elicit the needed hydro supplies in particular that would be needed to bring forth supplies.

And then finally, we would recommend to address our long-term concern that new peakers be exempted from the price caps on a going-forward basis.

Thank you.

MR. BARDEE: Thank you, Mr. Naeve.

Mr. Sobajic.

MR. SOBAJIC: Thank you.

First I would like to thank the Commission for organizing the conference and giving EPRI the opportunity to make a statement. The printed statement has been filed with the Commission.

The tight linkage naturally present between a market and its underlying physical system indicates that two approaches exist for mitigating prices in a market.

Market prices can be mitigated directly by changing market management practices as well as indirectly by changing the physical system that the market represents.

Both approaches can be also used in a concurrent manner.

Technology-based solutions provide effective price mitigation by improving performance of the physical system underlying electricity prices in the West--the Western Power Grid.

At present, various capacity bottlenecks and resource adequacy problems limit the ability of the Western Grid to deliver electricity to where it is needed.

These delivery deficiencies impact electricity prices. Improving the Western Grid to remove critical transmission deficiencies not only can mitigate p4rices in the near term but can also provide the infrastructure for growth over the longer term.

The obvious answer of constructing new lines is a long-term technology solution for mitigating prices arising as a result of the grid capacity limitations.

Less obvious are various near- and mid-term technology solutions available now that can be applied to mitigate prices in the West as soon as the coming winter.

Five such solutions, all technically mature and in use on power systems in the United States and broad are:

Dynamic Thermal Circuit Ratings technology;

Real-time Monitoring of Conductor Sag technology;

High-Capacity Low-Sag Conductors;

Flexible AC Transmission System devices; and

Real-time Technologies for Grid Operations.

The physical changes possible in the near term center on exploitation of unused grid capacity and a complete engineering background exists that would enable optimum physical operation of the grid in the longer term.

This background, developed over the past 30 years, defines what parameters of the grid to monitor, how to assess grid behavior, and the theory and extensive engineering practice for grid control.

By contrast, the present-day understanding of power markets is minimal. Agreement is lacking at the fundamental level about what parameters to monitor and how to assess them.

Clearly wholesale and retail prices are critical measures, but do other parameters exist that could better capture the market behavior?

Certainly the linkage with gas pricing and availability is becoming increasingly important. With understanding of how to monitor, assess, and control power markets at such a basic level, enormous work lies ahead for R&D organizations and academia alike.

Thank you.

(The printed statement of Mr. Sobajic follows:)

MR. BARDEE: Thank you, Mr. Sobajic.

Mr. Tallman?

MR. TALLMAN: Thank you.

My name is Mark Tallman, the Director of Origination for PacifiCorp. I would like to clarify that I represent the regulated merchant function of PacifiCorp and their format comments are not intended to represent our unregulated affiliate PacifiCorp Power Marketing.

PacifiCorp provides retail electric service to nearly 1.5 million customers across six Western States. In addition, we operate two electric control areas, and we have generation that is located in nine Western States.

We strive also to provide reliable retail electric service at reasonable prices. Based on this dual responsibility, we called on the Commission in the fall of 2000 to implement soft price caps in order to restrain runaway prices due to extreme capacity reserve shortages at the time.

We also heeded the Commission's warnings and prudently purchased material amounts of power in the forward markets. That prudent action has proved to be very costly to us.

At the current time, and during those hours when our portfolio of resources exceeds our loads, we are only able to resell that portion of our surplus load at prices up to the hard cap, rather than at prices up to what we paid.

More disconcerting, however, is the possibility that current California-centric hard cap methodology may increase the risk of power supply shortages in this upcoming winter.

Specifically, the ability of load-serving entities may be impaired during a cold snap due to the potential disconnect between the market-oriented principles that drive how the cap is currently calculated and the supply mix that is relied upon during an event to those load-serving entities outside of the California ISO control area.

Given this reliability concern, we appreciate the Commission's current initiative to consider how its price caps can be adjusted to better work for the millions of Western Electric customers who are not within the ISO control area.

The supply/demand balance, as you have heard, can be tight for this upcoming winter season. Nobody is quite sure how tight it could be. For us, as well as many other load-serving entities in the Pacific Northwest, the crisis occurs during an extended cold snap.

In the event the Northwest Power Pool declares a Stage I, II, or III emergency, the California ISO's price caps may be inadequate to ensure sufficient generation, and the WSCC is available to cure the reserve deficiency.

The Commission can reduce the risk of outages under this situation by permitting some additional price flexibility.

PacifiCorp specifically recommends that the current price cap methodology be revised, so that during any Stage One, Two or Three emergency and alert that's issued by the Northwest Power Pool or another security coordinator in the WSCC, that the level of the cap be adjusted to be the higher of the then-effective cap that's in effect from the California ISO previous Stage One alert, or a fixed dollar per megawatt hour amount. And for the purposes of today's discussion, we would throw out $250 as an amount to discuss.

With that, I'd like to yield the rest of my time.

MR. BARDEE: Thank you, Mr. Tallman. Mr. Theaker?

MR. THEAKER: Thank you, Mr. Bardee.

I'm Brian Theaker. I'm the Director of Regulatory Affairs from the California ISO. I want to start by thanking Staff for allowing the ISO to share our thoughts on West-wide price mitigation today.

For the ISO, the price mitigation imposed by the April 26th and June 19th orders is critical. The need for that price mitigation still exists.

California escaped the disasters forecasted for 2001 due to a combination of good factors: Moderate weather, heroic conservation by the citizens of California, the addition of new generation, and last but not least, the price mitigation orders themselves.

Some fundamental things have not changed since then. The West's aging generation fleet is now a year older, and the maintenance season for that has begun. You'll recall that the California crisis was precipitated in the winter of 2000 by a number of units going on forced outage to address deferred maintenance.

Second, as the census figures show, the number of people that moved to the West between 1990 and 2000 are still there. They have not moved back. Therefore, the load is still there, even though we are only seeing a temporal effect of conservation.

Third, an amazing statistic is that Los Angeles received more rain than Seattle last winter. That means that low Pacific Northwest hydro conditions will remain low if not worse.

Fourth, Path 15, the transmission corridor between Northern and Southern California, remains a bottleneck. We have not yet added the third line. And that will constrain the ability to move badly needed resources not only into Northern California but also into the Pacific Northwest.

Finally, new generation has been added and more is coming, but a generator on the bus is worth two at the CEC. And moreover, we're waiting to see or are now seeing effects of infrastructure problems within California as this new generation comes on line.

For the ISO, the bottom line is this. The competitive market that we all yearn for has not yet emerged from the chaos of the last 12 months. Price mitigation regrettably will be necessary for winter and for next summer at a minimum.

Some fundamental things have changed, though. The IOUs have been dragged into financial crisis by unjust and unreasonable rates over the last 12 months.

The state now finds itself in the extraordinary role of purchasing electricity for the IOU's customers. The ISO finds itself in the unenviable position between the rock of the Commission's orders to ensure a creditworthy purchaser and the hard place of the conditions imposed on it by the only creditworthy backer available in the state of

California.

Creditworthiness colors everything in California, there's no doubt, and we all hope that eventually CERs will be out of the power buying business. Today is about price mitigation, not about creditworthy concerns, however.

The ISO supports the existing price mitigation methodology. We believe a few modifications should be investigated to make this necessary tool even more effective.

First, we ask the Commission clarify the must-offer obligation as it relates to long startup units. The uncertainty of this hinges on the word "available". For generators, the word "available" means a unit is not available if it is shut down for economics.

Interestingly enough, these same generators support the ISO's definition as it appears in their RMR contracts. That is, a unit is available if it's not broken.

Having generators decide what is and what isn't available is what got us to the need for the must-offer obligation in the first place. And while it may not be fair for every individual unit with market-based rates in the portfolio to recover -- I'm sorry, to operate at an economic loss under some low load conditions, it's also not fair to guarantee a recovery of a generator's uneconomic costs to allow them to make even greater profits from the rest of their unit with their market-based rates.

A possible solution may be a cost-of-service approach or, barring that, to ensure that startup and minimum load costs are reimbursed for many market profits made.

Second, operating a power system requires the ISO be able to move generators up and down, both for local and system reliability reasons. The must-offer and the proxy bids has created effective tool for incrementing or increasing a generator's output. But daily, the ISO sees constant, unreasonable offers to reduce or decrement a generator's output.

This effectively is a bid meaning that the generator would be willing to buy energy's from the ISO's market and forego the cost of production.

The theory ought to be that an owner would be willing to buy to offer a DEC bid at any cost that was below the cost of production.

The reality is that daily the ISO cedes large, negative decremental bids that are unreasonable from generators. The ISO's proposed solution is to extend the must-offer obligation to require reasonable offers to decrement power if not cost-based proxy DEC bids.

The ISO supports the position it's always maintained to eliminate the 10 percent adder as an unnecessary and redundant requirement, given FERC's admonition to ensure a creditworthy purchaser which the ISO has striven to do.

And finally, in regard to the proposal in the notice of this conference, the ISO is not opposed to allowing the price limit to reset based on increasing gas prices without having that occur in a system emergency. But gas prices go up, and gas prices go down, and the ISO would be opposed to a mechanism that would reset the price only in one direction.

In summary, effective price mitigation afforded by the April 26th and June 19th orders is necessary. It should establish a reasonable market clearing price. But additional effort is needed to ensure rigorous scrutiny of costs offered above the market clearing price.

Thank you again for the opportunity to offer comments.

MR. BARDEE: Thank you, Mr. Theaker. At this point I'll turn it over to Staff for questions.

MR. ARMSTRONG: I'd like to start off. Mr. Julian, I was listening to your thoughtful comments and it looks like you support just about everything that the Commission is doing with one exception, and that was when to lift the price mitigation as opposed to September 2002. I wasn't sure if you were saying it should stay in place for an additional 18 months or another time I heard you say December 2003. Could you?

MR. JULIAN: What I indicated in my remarks was that the test should be when we have fully rehabilitated the credit of the investor-owned utilities so we can put them back in the market.

The Commission has in the Edison settlement established the target date at December 31, 2003, although I guess everyone's hope that that will occur sooner. But I think the basic point that I was trying to make was the duration of the price mitigation measures should be based on an achievement of practical objectives. And we talk about restoring the market to workable competition and so on.

Our objective is to have the IOUs back in the market. They need to be creditworthy, and I think that's a realistic objective.

MR. ARMSTRONG: Thank you. If I could switch gears now. Mr. Comnes, you had said that you would support a single price across the West, and you had reservations about the proposals to go to regional prices? Did you want to explain that a little more?

MR. COMNES: Yes. Thank you. We operate in all the major markets in the West, and we see a high degree of correlation obviously at certain times, you know, demand conditions in one area will push the market up in that area relative to others.

But if you really want to see power move to the Northwest when there's an Arctic condition up there, it's going to be in part solved by the incremental hydro generation that does reside in the Northwest, but it's also going to be resolved by incremental thermal generation in the desert Southwest.

And I think the Commission would really be being counterproductive if they limited prices in the Southwest during those times that the demand is pushing prices up in the Northwest.

So I would suggest if you go to some sort of gas based index, make it a higher of Sumas, Malin, PGE City Gate, or SP-15.

The Duke proposal actually gets you there, but I would just suggest it would be a higher of. One of the problems we have as marketers is we do have access to transmission capacity.

We have a lot of scheduling capability, but if the cap is at one level in one region, we want to buy it there, we want to source it in that region, transport it up. We can't buy it above the cap or we won't get cost recover because marketers have no condition to sell above the cap.

If the cap was the same in both, we'd have a little more headroom to get it to the right market. We were unable to sell to Nevada Power on July 2nd, for example, just because even though there was probably power available in the Northwest that was making itself available in the Northwest in that case because of transmission costs and a cap that was too low relative to the market costs that day.

MR. GELINAS: Mike, I was interested in I think one of your last comments which had to do with exempting new generation. I have a couple of questions on that. It's not the first time I've heard that proposal, so I want to make sure I understand it. Your written comments seem to talk about new generation. You mentioned peakers specifically. Are you distinguishing? Is it a certain class of generation or just new generation first of all?

MR. NAEVE: Quite frankly, I would exempt all new generation. I think the problem is most pronounced for peakers. Anytime you have a price cap scenario as you have now where the most expensive unit recovers only its marginal cost, you're going to disincent people from constructing those marginal units, because that's all they get is their marginal cost. So the problem is most pronounced for peakers.

I also think, though, that if the Commission wants to provide encouragement for the construction of new generation in a world in which prices have constantly changed in California, even in situations where you were selling at a level that was below an existing cap and then later on you're subject to refund because at another time they conclude that that cap was too high, you don't have a lot of confidence in what's going on. And if it were made clear at the very beginning that new generation would not be subject to the cap, then I think you are much more likely to incent parties to build generation than the current situation where the prices are in an ever-changing environment and they quite frankly don't know what the world will be like in six months or 12 months.

MR. GELINAS: Would it matter whether the entity owned existing generation? I'm drawn to the concept for an entity that owns no generation in the market, I'm a little concerned on pink and blue megawatts for people that have existing generation that they can sell and must offer under our mitigation but then have unregulated megawatts in a portfolio, so whether that might cause some gaming.

MR. NAEVE: That's a fair point. And I must admit, it is difficult, for example, if you had a dominant seller and you permitted the dominant seller to build more generation and have a portion of that deregulated if they could through their existing supplies affect prices, that they would then realize from their higher priced units.

So perhaps it would need some tinkering. I do believe, though, as a general rule for most sellers and perhaps you can carve out one or two and say, and you could do some sort of analysis and say people over a certain size have to come in on a case-by-case basis before they qualify, they give you the opportunity to review that. But as a general rule, the market is better off with more generation. And in some ways, I'd rather have a dominant supplier building up more generation than not have it built at all.

So I think a case could be made to even exempt generation from dominant suppliers.

MR. GELINAS: Does anyone on the panel have a thought on this one? Because this is one I've been struggling with personally. Bill?

MR. JULIAN: I think it's no secret that the California Power Authority has been exploring the possibility of the state investing substantially in peakers. And while that's not necessarily an outcome that any of us would consider optimal, it certainly is attractive to have the state make that investment, amortize it over a long period of time and stay out of the market if what it's going to be faced with in the market is an extremely high and unstable price situation. And that's why I think that the Commission's, as I understand it, the basic approach underlying the Commission's price mitigation regime is to move to the extent possible away from short-term spot relationships and that the basic concept of a stable and predictable price cap that doesn't change on very short-term gas price movements and so on and so forth was to provide that stability and that predictability.

I think that it's certainly possible to devise all kinds of specific, generator-specific scenarios that would justify one pricing regime or another. But from the standpoint of trying to get stability back in the market, I think it's very problematic. And frankly, the state of California is trying to develop an insurance policy against what might happen if the price mitigation regime were relaxed in the ways being suggested.

MR. NAEVE: Although I would say I don't think the right long-term answer is to impose a price regime that makes it uneconomic to bill peakers then have the government get in the business of billing peakers. That just strikes me as the wrong answer.

MR. JULIAN: And I wouldn't disagree with that, but we're not talking about a long-term situation with this price mitigation proposal. We're talking about another 12 to 24 months, 27 months.

MR. COMNES: The current mitigation is sowing the seeds for another reliability crisis. We've seen a lot of peakers come off the map, some of them are being subsidized by the state of California, but outside of the West a lot of projects became uneconomic. So it's really the peakers that need some sort of escape from the current mitigation because despite what the FERC has said in its orders, the peak unit makes its money in the peak hours, and you've got statements in your orders that say, oh, you'll make it bilateral markets. You'll make it in other hours. That's just not true for a peaker. It's factually wrong. It's still in the FERC order.

So I'd say an exemption for new generation or new peakers is certainly a second best solution, but I think it's something you have to look at. And I would argue that how would a megawatt, whether it's owned by a dominant or a new entrant make any difference in terms of what price it's going to make? A dominant generator if they're dominant can control its output. I would argue that, you know, they -- I don't know you can say that more megawatts would not be good for the system at this point.

MR. MILLER: So under that scenario, and I'll ask Mike or Alan or anybody else, under that scenario, you would have a clearing price for blue megawatts which are the existing generation, and then pay as bid or clearing price for new generation? I mean, how would that work? Because we are still talking about clearing prices here.

MR. NAEVE: Well, first I'd say I generally agree with Alan. I think the more megawatts built are good for the system. It probably doesn't matter who builds it. But I don't think you'd have a clearing price for the blue megawatts or the new generation. They simply wouldn't be subject to a clearing price. They would sell at competitive prices.

MR. MILLER: Pay-as-bid.

MR. NAEVE: Pay-as-bid.

MR. COMNES: I think the key thing is you can cost justify above cap transactions, but you can only justify with some absolutely unrealistic measure of marginal costs, or at least absolutely unrealistic with respect to a peaker. A peaker has to earn capital recovery, startup costs, any emission costs on that marginal output, and right now, you can't do that.

MR. MILLER: But take me back, because obviously the Commission and the Staff did struggle with this throughout all last year. On what -- because every firm differentiates the way that they cost justify a peaker. Is it over ten years? An assumption that it'll run 1,000 hours? Or, you know, I don't think that we're ever going to get it right in bounding how much a peaker needs, because we're never going to make the same assumptions you are.

So what you're saying is, just let the peaker set whatever price it can get. Is that right?

MR. NAEVE: That's what I would say.

MR. GELINAS: The only thing that troubles me on that -- I'm going to try one more. When we had a mixture of cost and market for the ancillary services when this experiment began, we saw nothing but distortions and problems with two pricing regimes out there. I'm still concerned in a period of shortage why there wouldn't be an incentive to -- maybe we can limit it in some way, but it wouldn't be an incentive to sell from the megawatts that are not subject to price mitigation and to somehow have the megawatts which are unavailable just find the incentives there to be there. I'm not saying that would happen, but it's what the Staff and a lot of us have been struggling with, notwithstanding the notion that it seems more megawatts in a tight market is exactly what we want to induce.

MR. NAEVE: I guess a couple of thoughts here. First, we're not talking about a situation that's going to go on forever. We're talking about a situation hopefully, as Mr. Julian said, that's an interim issue, not a long-term issue. In the long term, you won't have blue megawatts and red megawatts. You'll just have megawatts.

Secondly, you do have a must-offer obligation and you have enforceability with respect to that and a lot of information with respect to the units that are running and not running. So I'm not sure in the short run that's going to be that much of a problem.

I think the problem I see and even California sees the same problem, that there aren't adequate incentives to bill peakers, so they have the state billing the peakers. My solution is let's get private investors to bill those peakers. Let's just give them the adequate incentive to do it.

You could very well have a situation where people do earn very high prices on those peakers, but keep in mind, those are sales that would not otherwise occur. Those are units that wouldn't otherwise be built. And we'd rather have them than not have them. We went through this very scenario when we passed the Natural Gas Policy Act where we deregulated certain new wells and then kept prices on all the old wells. And the net effect of that was people earned some relatively high prices on lots of new wells, but in a very short period of time, we had a surplus of capacity as well.

From 1978 where we had severe shortages to 1981 we had a huge gas bubble that lasted for five years. So it's not necessarily a bad thing.

MR. GELINAS: Thanks.

MR. THEAKER: If I could add -- I'd just like to add one thought. The ISO has wrestled with this question.

We issued an RFB for peakers back in 2000 when we thought the summer of 2001 was going to be a train wreck. It turned out to be just some squeaky wheels ultimately. But it's a difficult issue because you don't want to create a price signal that is so massive to accommodate the new peaker generations, which really you hope are the band-aid, the short-term thing that you have to build in a year or two to get through the problem. But you don't want to turn those into the 10, 20-year marginal resource if you can avoid it.

So the way we dealt with it was to try to cover what we thought were most of the capital costs through an offline payment and then to require the unit to be a price taker in the real-time market in the hopes that you wouldn't need to create the huge market clearing prices to support the construction of temporary generation. That's how we dealt with it.

MR. ARMSTRONG: By an offline payment, you're talking about some capacity charge?

MR. THEAKER: Correct.

MR. ARMSTRONG: Creating a capacity market in a sense with a must-offer on the energy?

MR. THEAKER: That's correct. The ISO's contract that we issued with the RFB basically allowed the ISO to direct 500 hours of operation for the three source during the summer period June through September but then paid capacity payments on an as-available basis through that time.

MR. NAEVE: I would just point out that in effect is almost the same thing. You're taking an approach not affected by the price caps. These long-term acquisitions are outside the scope or the realm of the price caps to bring forth a new supply. And maybe the best way to contract for that supply is through a long-term contract. Another alternative is through having it available for short-term prices. I would say kind of let the market choose which is the right way to go.

But either case, what you're doing is providing for resources outside the limitations of the price caps.

MR. ARMSTRONG: Mike, I don't mean to --

MR. GELINAS: Yes he does.

(Laughter.)

MR. NAEVE: I don't mind.

MR. ARMSTRONG: I'm confused a little bit on something you said, and it was something like was mentioned on the earlier panel about thermal might not always be the marginal unit, and the winner more than likely could be the hydro instead of the thermal. And to recognize the value of that hydro, there would have to be some sort of opportunity pricing but that this would only be doable after the fact, after the snowpack is measured and sometime next year.

So then I heard you say that a recommendation was to lift the price ceiling either gradually or insert a circuit breaker when there's a reserve deficiency and several other options. But I heard you saying that it's very difficult to try and price hydro based on an opportunity cost model. Is that correct?

MR. NAEVE: What I'm saying is I don't think we can artificially create a cap based on our appreciation of what the opportunity cost is. We don't know what that is, nor does the owner of the hydro resource. The owner of the hydro resource is simply attempting to forecast what its opportunity costs are. And based on its own internal forecast, we may or may not persuade them to offer supplies this winter. It depends on the price this winter and it depends on their forecast of its future value.

And the point I attempted to make was it's assessment of that future value depends a lot on its assessment of how much it's going to have to sell come next winter. Will it have sufficient supplies to meet its own load needs? And that'll be its highest need. And will it have sufficient supplies then to sell into the summer to meet other people's needs at those prices? And of course the availability of the supplies next summer affect what the prices will be next summer, too. So there are a lot of factors that go into that calculation.

My only concern is, I listened to the various modification that have been suggested to the existing price caps, and none of them solved this problem. None of them established a price based on anything other than the cost of a thermal unit when the swing unit will be a hydro unit. And the other factor I mentioned is that they won't know what their availability may be until later in the winter.

So if they have to make a decision in December or in January or maybe even early February as to whether to supply their resources into the Pacific Northwest, and they might be coming out of British Columbia or somewhere else, but whether to supply those resources today or hold them for next summer, they'll be doing so without full knowledge as to what they're going to have available next summer to meet their own needs.

So it could well be that the price has to be fairly high before they're willing to let go of those supplies. That would be the case in my situation. I wouldn't want to let go of that if I'm limited to resources right now, I haven't had a major snowfall yet, I don't know what it's going to look like next year, I'm going to hold onto those supplies, because I may well need them. But if the price is very large, I may let them go, capture those dollars and use them next fall to buy other supplies. So I'm trying to make that calculation. And none of the other proposals that I've seen solve that problem. And if you don't solve that problem, you may not have the hydro resources you need to avoid shortages this winter.

MR. GELINAS: Mike, it almost sounds like you're exempting hydro as well as peakers from the way I'm -- MR. NAEVE: Well, no. Hydro already is exempted from the must offer.

MR. GELINAS: No. But I mean, you're talking about opportunity costs.

MR. NAEVE: No. What I'm saying is if -- no, hydro is covered by the price cap today.

MR. GELINAS: Right.

MR. NAEVE: But the problem is, the price cap may not be sufficiently high to incent them to make their sales. So if you have a price cap based on a thermal unit, even if we adjust that price cap of gas prices go up in the Pacific Northwest or somewhere else, if the price cap is based on a thermal unit, they have to sell at that price or less. And that price may not be enough for them to let go of that scarce resource. That's what I'm saying.

MR. GELINAS: And so your proposal on the price end is to do what with it exactly?

MR. NAEVE: My proposal is to raise the cap. Eliminate the cap or put a circuit breaker.

MR. GELINAS: So exempt them from the price cap in a sense or --

MR. NAEVE: I wouldn't apply the price cap.

MR. GELINAS: Wouldn't apply the price cap.

MR. MILLER: Adopt a circuit breaker cap.

MR. NAEVE: Right. Adopt a circuit breaker cap like you have in PJM, in ERCOT, New York, NEPOOL and so forth. And again, I recognize this is a very politically difficult thing for the Commission to do because if you look at the chart that Alan put up earlier, you can see prices that were very high. You put in place your mitigation effect, and prices are very low. And how do you have the confidence that prices aren't going to back to where they were the other day?

And I think things have changed a lot. A number of the panelists have discussed what is changed. We have more supply. We have significantly reduced demand. Some of that demand quite large, and we know for certain will not be here this winter. The aluminum plants that are out, 2,400 megawatts there and elsewhere.

We also have California now with significant quantities under long-term contracts.

Another comforting fact is that because the Pacific Northwest and the rest of the west and even in California, so much of our anticipated needs are covered by long-term contracts. If spot prices do peak, it's not going to affect the price of those previously committed supplies, so it's just on the margin that will be affected by the spot prices.

So because we are buying much fewer supplies on the margin, it'll have I think the prices are less likely and secondly, when they do peak, they'll have a lesser effect on our overall cost.

MR. MILLER: Bill? Bill, I notice you were nodding there when he was talking about the difficulty of setting the opportunity costs for hydro and the coral areas, obviously there's a danger under certain circumstances that that may not be available, and as we saw, the installed capacity for hydro for the west is huge. Do you have any concerns about the effect of the current mitigation, even with some of the modifications taken away, possibly because there is, you know, it sets it at the thermal unit level, and it's impossible to set a limit based on hydro that you can run into some problems down the road?

MR. JULIAN: As I understand the discussion both in the earlier panel and this one, really any energy limited unit is going to have an opportunity cost rationale for higher price and there's going to be an issue. We saw the same thing in California when we were concerned about mission controls or mission credits limiting energy output.

I guess first, it seems to me that it's a technical issue about the extent to which the units are in fact energy limited. It's also a highly practical and concrete issue that I think you would want to look at on the basis of a factual record. The extent to which the hydro units are in fact going to be on the margin this winter for specific load-serving entities in the northwest is probably something that it would be interesting to hear from those load serving entities, and you might want to look at it.

But I guess I don't see the sort of theoretical problem of how do you price energy limited units as driving what I think is essentially a practical question about modifying west-wide price mitigation measures. I guess I would be concerned that the baby of that technical issue or the bathwater of that technical issue, not throwing out the baby of a return to stable markets throughout the west.

I don't know if that answers your question, but?

MR. GELINAS: Can I go back on the peakers for a minute, Mike, and come back at you but from a different perspective, not new and old. What we've talked a lot about the difficulty in citing peaking units come into a market additional supply that you need, and one thing we haven't talked about is demand reduction as a way to handle this problem, and how we would go about pricing that. So maybe I'd like to throw that open to the panel to see is there something concrete that we have as proposals for how to do peaking by demand reduction and how to price it?'

MR. NAEVE: I know Portland General has developed, over the last year-and-a-half, a fairly aggressive demand buydown programs where they propose to buy down demand from the retail load at fixed prices in exchange for the functional equivalent of a capacity type payment.

But what they've discovered is the prices at which that makes sense is roughly $200 a megawatt hour, and if prices are capped at $90 or $100 or something like that, it's simply not economic to buy down demand at that price; you won't have any takers. So that's the problem.

MR. GELINAS: Are you in a sense saying treat demand like a peaking unit and exempt it from the price?'

MR. NAEVE: No, no. I'm just simply saying if you offer to purchase demand at the current price cap, you won't get any offers.

MR. GELINAS: But what if the current price cap did not apply to a demand buy down, much as you were I thought --'

MR. NAEVE: Well, I'm not sure it makes sense.

Oh, you're talking about during the peak hours?

MR. GELINAS: Yes. I'm trying to get some symmetry here between supply and demand.'

MR. NAEVE: I think that would be a good idea too but certainly if a, let's say hypothetically, even if you had the current price cap in place, and we created a shortage because --

Alan keeps trying to -- do you want to say something, Alan?

MR. COMNES: Go ahead.

MR. NAEVE: Even if you created a shortage because the current prices are not enough to bring forth the supplies you need. In that situation, you're going to recover, more than likely, the cost of buy down demand from your retail customers, not from this agency. So if you were to go to your state commission and ask for authorization to buy down demand and offer $200 to do that, they may very well approve that. So it could make sense.

I don't know if you want to exempt it from these price caps. I'm not sure how that would work.

MR. GELINAS: I'm just trying to explore that. Alan?

MR. COMNES: I think if we're all in the world of second best solutions, you know, you'd have some incentive to market operators declare a price for demand buy down and you would get the demand reduction that you need. And I would say that if you're not willing to look at the cap in terms of going to a circuit breaker, absolutely you've got to exempt peakers, you've got to exempt demand side. You can see huge demand response prices get into the $200 range. We saw it in the northwest because there is no disconnect between retail and wholesale prices.

In California, you don't have that connection. I don't know what the state of demand reduction programs are at the ISO but at least what I heard secondhand is they had sort of broken down. So, yes, an exemption for demand side is absolutely essential. But again I have to come back to first best versus second best. I mean, you're going to have an exemption for peakers, demand side, new supply in general, hydro. What's left?

What we do as marketers is bring incremental supply where it's available at the least cost and bring it to buyers where it's most demanded and I submit to you that the best thing that you can do for the west at this point is just lift the cap to some level and I'll tell you, the forward curve right now through this winter is well below $91.87 and we're only talking about situations where the unexpected's going to occur. Now granted, load serving entities are going to care a lot about that but I think you just need to have something that'll respond to those less-than-normal conditions, and if load-serving entities could buy all the power they want right now, for well below $91.87, they're basically not buying because they want to keep their options open that prices might fall or the demand might not materialize on their end.

MR. THEAKER: Let me address both the first best, second best, and also the state of the ISO's demand programs. I had to yield to homespun analogies but I'll use one here. I have a dog at home which he is on a strong leash because if you take away the leash, he is gone, and when he comes back in a couple of days, he's probably got chicken feathers on him. I would like that dog not to have to be on a leash. But me wanting him to not be on a leash doesn't mean that I can go out and take him off the leash.

The reasonable thing for me to do is to build a fence around the yard until the dog gets used to the fence, and then take the fence away. I think we are just talking about second best solutions today. We do not yet have the competitive market that I think we all like in the west in order to lift the price caps entirely. So I think we are only talking about second best solutions today.

In terms of demand response programs at the ISO, we strongly believe that demand is a necessary part of the market. We've been trying to encourage it. Up until 2000, the only load tool that we had was the interruptible service provided by the IOUs under the state rules, and that was effective but it's just one tool. We've been somewhat hamstrung in our efforts to develop other tools because of where we are financially in the whole market and dependent on surges of creditworthy backers. So that has scuttled some of the efforts for 2001. We know that efforts are underway at the PUC. We hope they're successful. We think that's the best solution.

MR. MILLER: Boy, life in Fulsome's a lot more agricultural than I thought.

MR. COMNES: We have a creditworthy buyer for load in the northwest. I mean, again, you are here today to understand what's going to happen with the price cap in the northwest is my understanding, and again I would argue go for the fence and let go of the leash and consider circuit breaker caps.

MR. GELINAS: Bill, could I ask you to comment on this issue? I would very much like your thoughts.

MR. JULIAN: The CPUC has considerable experience with demand side programs. The interruptible program was in effect a capacity purchase program that operated for a number of years, and still operates. I guess the only thing I would suggest based on that, on the Commission's experience, is don't underestimate the cultural changes that are necessary for the loads. The interruptible program was something that in fact involved significant changes to work cultures and to operations of the loads that were being interrupted. And for that reason, the process of aggregating in effect biddable load, is operationally fairly complex.

California has invested a substantial amount of money in the metering that would be necessary for widespread load management, but the reports that are coming back is that the folks who are getting those meters have a fairly steep learning curve to go up. There are some loads that are capable of doing it but it takes time and takes significant operational changes, and I won't bore you with the details on that.

But they are essentially retail issues, they require metering, they required operational changes by the loads themselves.

MR. COMNES: I feel like I'm the truth squad today. And how are you ever going to start those programs if you don't let the market price go above $91.87. I don't know how you're going to start a cultural change that will be in effect by the end of the transition if you don't get the market price signal out today.

MR. MILLER: No takers, huh?

MR. TALLMAN: I'd like to make a short comment. Pacificorp Two is very concerned about a long-term price signal to spur the creation of peakers in the marketplace.

We want to see a wide range of resources, we want to see a wide range of heat rates, and we want to see liquidity in-depth in the market.

We also have undertaken some demand programs. We've undertaken demand exchanges where customers can bid in their load. We've undertaken efforts to enter into bilateral arrangements with large customers, have the ability to curtail load. And I would like to reemphasize, you cannot under estimate the difficulty in trying to make those happen. Every customer has their unique issues.

And maybe just to try to bring this back to a reference point because our concern is one of reliability, our concern is specifically being able to purchase power during stage emergencies in the winter in the northwest. And there was a reference to the Northwest Power Pool assessment for this winter by the previous panel. And there's a key factoid in that assessment, and that key factoid is that for every one degree of temperature below normal translates into about 300 megawatts worth of load. So for a typical cold snap, where we're running anywhere from 19 to 22 degrees below normal, it's roughly 6000 megawatts of load.

So although many of these issues are very important and they're good for the long-run health of the industry, our concern is immediate. And while we do buy into the notion that we want to keep our eye on the ball and where we're heading. We can't forget the fact that it's almost November 1st. And we're heading into a time period when the key issue, quite frankly, is can we buy enough power during an unexpected cold snap, during times when unexpected events take place, and the key question has to be, if some strange chain of events should reset the cap in California, $28 as Mr. Comnes alluded to, would the Commission and would we be pleased with that in terms of serving loads. And so I'll just stop there.

MR. ARMSTRONG: Could I just follow up on that. Mark, could I just follow up on that?

MR. TALLMAN: Certainly.

MR. ARMSTRONG: In your opening statement, I thought your main concern was that you represented a load-serving entity and you were worried that at times when you went long in the market and your load didn't materialize, you were capped at your ability to resell this and recover your whole purchase power cost. And I'm wondering has that concern of yours sort of run its course now that you're going to into the winter and you represent, I presume, a winter peaking utility?

MR. TALLMAN: No, that concern hasn't totally left us. But that's an economic concern. And the concern we are primarily focusing on, and that's the nature of our proposal being simplistic, is that during a stage alert, it is past the time of economics. You're at a time when you need to serve the load. And our concern being that on a forward basis, you literally are unable to purchase the products you really need in order to run a power system and shape against a load.

For example, you cannot go buy super peak products over the counter on a tradable basis. You have to buy products that don't fit your needs. And as a entity that has a wide mix of resources, thermal, hydro, I think we've got one in every basket, contractual, and the market, and the market is a valued resource because the market acts as a sync and a source much in the same way as the physics drive a control area, and you just are unable to purchase the exact products you need to match your load. Thus the creation of the years of the active bilateral market in the northwest, at least.

MR. GELINAS: Mark, did I hear one degree equal 300 megawatts? Is that what I heard?

MR. TALLMAN: Yes, that's what my research folks told me.

MR. GELINAS: Is that for the Pacificorp System or?

MR. TALLMAN: That was a factoid in the Northwest Power Pool winter assessment.

MR. GELINAS: The Northwest Power Pool. Okay.

MR. TALLMAN: Yes.

MR. BOOTH: I wanted to follow up on that. We've heard several speakers talking, both in this panel and one in the last panel about sort of concerns about a tight, potentially tight winter, and I'm interested to hear from maybe some other folks if they have any perspectives on this about how concerned the Commission should be about that. I think Mr. Comnes mentioned maybe that's not so much a certainty, it's just you know something that's a potential out there, but if you had any other perspectives on that, I'd be interested.

MR. COMNES: I think it's of great concern. I mean, we don't know what the rainfall's going to be. It'll start raining in November and the very first precipitation readings will come in late November and December. But you can, you know, you can buy below, but there's a certain expectation in the market that's showing adequacy right now. But I don't mean to portray that you don't have anything to be concerned about here. You need something that will respond to conditions. I'm portraying them as west-y conditions so a cold snap in the northwest affects the price in the desert southwest. That's the message I'm trying to get across. You need a cap that'll respond to that condition that's not driven by the ISO reserve deficiency.

MR. BOOTH: Is part of the message here that having a price mitigation doesn't provide the type of flexibility that you might need in unusual weather conditions in the west? Is that sort of the message?'

MR. NAEVE: I think if we have good conditions this winter, then the prices that are brought forth at the current cap may be more than adequate. If we have bad conditions, they may not be adequate and we don't know at this stage, so it doesn't provide potentially -- if conditions were bad, it would not provide sufficient flexibility and we don't know at this stage.

I do think it's kind of interesting that the panelists that you've heard from who actually represent load-serving entities in the northwest have expressed concern about availability of capacity this winter, under potential load conditions and market conditions. Parties representing California, their focus is different. They're not going to have a peak this winter. They are in a different market situation, and their focus is more on day-to-day administration of the cap. So we do have a different focus. We are actually worried about keeping the lights on under potential conditions this winter but it's natural we'd have a different focus because we represent different parts of the market with different market conditions.

MR. BOOTH: Given the situation with the forward price curve at this point, is there more that the folks in the northwest who have load-serving entities could to do protect themselves?'

MR. NAEVE: Well, you can always buy on a forward basis if the supplies are available on a forward basis, to not only meet your anticipated load but more than your anticipated load. There's certainly a cost to doing that as well. And the more rational approach is to buy to meet your projected load and then to the extent that there's surplus, use short-term purchases that are available to do that.

You could to it the other way but it would probably be more expensive because you're then paying for capacity you don't need and even when you do need it, it'll just be for a few hours. So you're probably much better off buying even at relatively very high prices, it would be cheaper than buying, you know, 24/7 when you really don't need it or when you only need it for a few hours. So there's that equation.

And the other fact that if you do purchase long-term, you can resell at your purchase price; because the long-term purchases aren't covered by the cap but the short-term sales are. That affects that equation.

MR. BOOTH: But supposedly you can buy it below the cap right now on the forward market?'

MR. NAEVE: Yes, I would expect so. I'm not sure what the limits to that are. If everybody started buying substantially in excess of their anticipated needs, you'd run into a problem, but today capacity is available.

MR. COMNES: You may have the situation where you have a load-serving entity that's going to be unhappy because they're going to be capped, they're actually over-bought, and they're going to have trouble selling off on that peak day. You know, as a power marketer, we are able to back purchases and sales so we are neither naturally long nor short at this point, and if we have a position, I don't even know what it is.

But again I think we looked at our technical analysis and the incremental supply is as much from the southwest as it is from the northwest. We actually predict that most of the water will flow this winter. It's really going to be eliciting incremental thermal supply from the southwest and that's why a west-wide cap matters, that's why export capacity into the region matters. You know, so that gets us to the conclusion of west-wide circuit breaker.

MR. BOOTH: Mr. Tallman, did you have a reaction?

MR. TALLMAN: I'm not sure I have along reaction other than to say the question is how much do you buy. In other words, what contingency am I buying against. As an entity that owns generation that we have geographically dispersed, we rely on transmission systems to import into our load centers, so am I buying for a one-unit outage, a two-unit outage, a transmission curtailment, or a cold snap.

And the fact that there is a market and that there is a price in the forward market doesn't tell you the whole story, because the rest of the story is what's the depth of the market, what's the liquidity of the market and if the region went out to buy for this rather alarming 6000 megawatt number, I think we would find the answer to those questions somewhere along the spectrum.

So those are the issues that we would like to get to, which are where do we turn for capacity during a stage alert, keeping in mind that a stage alert, the first stage is just a prediction of not being able to meet loads. By the time you hit the second stage, you're there. And that's the issue that we are putting forth today and that we would like to try to find a tweak for.

MR. BARDEE: Were there any other questions from Staff?

(No response.)

MR. BARDEE: I'd like to thank all our panelists this afternoon. One thing I wanted to mention. Consistent with the notice the Commission issued in this docket on October 12th, comments in writing are welcome up to November 9th. All interested persons can file them here at the Commission. That's in Docket Number EL01-68.

Thank you.

(Whereupon, at 4:25 p.m., the technical conference was adjourned.)